UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

June 15, 2012

Mr. Mano Nazar
Executive Vice President and
Chief Nuclear Officer
Florida Power and Light Company
P.O. Box 14000
Juno Beach, Florida 33408-0420

SUBJECT: TURKEY POINT UNITS 3 AND 4 - ISSUANCE OF AMENDMENTS REGARDING EXTENDED POWER UPRATE (TAC NOS. ME4907 AND ME4908)

Dear Mr. Nazar:

The U.S. Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 249 to Renewed Facility Operating License No. DPR-31 and Amendment No. 245 to Renewed Facility Operating License No. DPR-41 for the Turkey Point Plant, Units Nos. 3 and 4, respectively. The amendments consist of changes to the Technical Specifications (TSs) in response to your application letters dated October 21 and December 14, 2010, as supplemented by letters dated December 21, 2010, January 7, 2011, January 28, February 22, March 3, March 9 (two letters), March 16 (two letters), March 23, March 25, March 31 (two letters), April 14 (two letters), April 22 (2 letters), April 26, April 28 (2 letters), April 29, May 11, May 18, May 19 (two letters), May 26 (two letters), June 7, June 9, June 21 (two letters), July 7 (two letters), July 22, July 29, August 5, August 11, August 16 (two letters), August 19, August 25 (two letters), August 29, September 14, September 16, September 30 (two letters), October 6, October 12 (two letters), October 14, October 15, November 9, December 22 (2 letters), December 31, 2011, January 10, 2012, January 16 (two letters), January 17, January 19, January 23 (two letters), January 25, January 31, February 3, February 15, February 23 (two letters), and March 15, 2012.

The amendments increase the licensed core power level for Turkey Point Units 3 and 4 from 2300 megawatts thermal (MWt) to 2644 MWt. This represents a net increase in the core thermal power of approximately 15 percent, including a 13-percent power uprate and a 1.7 percent measurement uncertainty recapture, over the current licensed thermal power level and is defined as an extended power uprate. The amendments change the renewed facility operating licenses, the TSs and licensing bases to support operation at the increased core thermal power level, including changes to the maximum licensed reactor core thermal power, reactor core safety limits, reactor protection system and engineered safety feature actuation system limiting safety system settings, and emergency diesel generator surveillance start voltage and frequency. Additional TS changes include reactor coolant system heatup and cooldown limitations, pressurizer safety valve settings, accumulator and refueling water storage tank boron concentrations, main steam safety valve maximum allowable power level and lift settings, new main feedwater isolation valves, and core operating limits report references. A complete list of the proposed TS changes and the licensee's basis for the changes can be found in Attachment 1 of the licensee's application (Agencywide Documents and Management System Accession No. ML103560167).

The NRC has determined that the related safety evaluation (SE) contains proprietary information pursuant to Title 10 of the *Code of Federal Regulations,* Section 2.390, "Public Inspections, Exemptions, Requests for Withholding." Accordingly, the NRC staff has also prepared a redacted, publicly-available, non-proprietary version of the SE. Copies of the proprietary and non-proprietary versions of the SE are enclosed.

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

Sincerely,

Jason C. Paige, Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-250 and 50-251

Enclosures:
1. Amendment No. 249 to DPR-31
2. Amendment No. 245 to DPR-41
3. Non-Proprietary Safety Evaluation
4. Proprietary Safety Evaluation (ML11293A366)

cc: Listserv

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

FLORIDA POWER AND LIGHT COMPANY

DOCKET NO. 50-250

TURKEY POINT PLANT, UNIT NO. 3

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 249
Renewed License No. DPR-31

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

   A. The application for amendment by Florida Power and Light Company (the licensee) dated October 21 and December 14, 2010, as supplemented by letters dated December 21, 2010, January 7, 2011, January 28, February 22, March 3, March 9 (two letters), March 16 (two letters), March 23, March 25, March 31 (two letters), April 14 (two letters), April 22 (2 letters), April 26, April 28 (2 letters), April 29, May 11, May 18, May 19 (two letters), May 26 (two letters), June 7, June 9, June 21 (two letters), July 7 (two letters), July 22, July 29, August 5, August 11, August 16 (two letters), August 19, August 25 (two letters), August 29, September 14, September 16, September 30 (two letters), October 6, October 12 (two letters), October 14, October 15, November 9, December 22 (2 letters), December 31, 2011, January 10, 2012, January 16 (two letters), January 17, January 19, January 23 (two letters), January 25, January 31, February 3, February 15, February 23 (two letters), and March 15, 2012, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Operating License and Technical Specifications as indicated in the attachment to this license amendment, and paragraph 3.A and 3.B of Renewed Facility Operating License No. DPR-31 is hereby amended to read as follows:

   A. Maximum Power Level

   The applicant is authorized to operate the facility at reactor core power levels not in excess of 2644 megawatts (thermal).

   B. Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 249 are hereby incorporated into this renewed license. The Environmental Protection Plan contained in Appendix B is hereby incorporated into this renewed license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance and shall be implemented prior to Unit 3 startup from the spring 2012 refueling outage.

FOR THE NUCLEAR REGULATORY COMMISSION

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Operating License
and Technical Specifications

Date of Issuance: June 15, 2012

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

FLORIDA POWER AND LIGHT COMPANY

DOCKET NO. 50-251

TURKEY POINT PLANT UNIT NO. 4

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 245
Renewed License No. DPR-41

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

   A. The application for amendment by Florida Power and Light Company (the licensee) dated October 21 and December 14, 2010, as supplemented by letters dated December 21, 2010, January 7, 2011, January 28, February 22, March 3, March 9 (two letters), March 16 (two letters), March 23, March 25, March 31 (two letters), April 14 (two letters), April 22 (2 letters), April 26, April 28 (2 letters), April 29, May 11, May 18, May 19 (two letters), May 26 (two letters), June 7, June 9, June 21 (two letters), July 7 (two letters), July 22, July 29, August 5, August 11, August 16 (two letters), August 19, August 25 (two letters), August 29, September 14, September 16, September 30 (two letters), October 6, October 12 (two letters), October 14, October 15, November 9, December 22 (2 letters), December 31, 2011, January 10, 2012, January 16 (two letters), January 17, January 19, January 23 (two letters), January 25, January 31, February 3, February 15, February 23 (two letters), and March 15, 2012, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Operating License and Technical Specifications as indicated in the attachment to this license amendment, and paragraph 3.A and 3.B of Renewed Facility Operating License No. DPR-41 is hereby amended to read as follows:

   A. Maximum Power Level

   The applicant is authorized to operate the facility at reactor core power levels not in excess of 2644 megawatts (thermal).

   B. Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 245 are hereby incorporated into this renewed license. The Environmental Protection Plan contained in Appendix B is hereby incorporated into this renewed license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance and shall be implemented prior to Unit 4 startup from the fall 2012 refueling outage.

FOR THE NUCLEAR REGULATORY COMMISSION

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Operating License
and Technical Specifications

Date of Issuance: June 15, 2012

ATTACHMENT TO LICENSE AMENDMENT

AMENDMENT NO. 249 RENEWED FACILITY OPERATING LICENSE NO. DPR-31

AMENDMENT NO. 245 RENEWED FACILITY OPERATING LICENSE NO. DPR-41

DOCKET NOS. 50-250 AND 50-251

Replace Pages 1, 3, 6, & 7 of Renewed Operating License DPR-31 with the attached Pages 1, 3, 6, and 7.

Replace Pages 1, 3, 6, & 7 of Renewed Operating License DPR-41 with the attached Pages 1, 3, 6, 7, and new page 8.

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

Remove pages	Insert pages	Remove pages	Insert pages	Remove pages	Insert pages
x	x	3/4 3-8	3/4 3-8	3/4 7-2	3/4 7-2
xiv	xiv	3/4 3-9	3/4 3-9	3/4 7-11	3/4 7-11
1-5	1-5	3/4 3-11	3/4 3-11	--------	3/4 7-11b
2-2*	2-2	3/4 3-14	3/4 3-14	3/4 8-5	3/4 8-5
2-4	2-4	3/4 3-18	3/4 3-18	3/4 8-6	3/4 8-6
2-5	2-5	3/4 3-23	3/4 3-23	3/4 8-7	3/4 8-7
2-6	2-6	3/4 3-24	3/4 3-24	3/4 8-8	3/4 8-8
2-7	2-7	3/4 3-26	3/4 3-26	3/4 8-9	3/4 8-9
2-8	2-8	3/4 3-27	3/4 3-27	3/4 9-1	3/4 9-1
2-9	2-9	3/4 3-28	3/4 3-28	3/4 9-15	3/4 9-15
2-10	2-10	3/4 3-29	3/4 3-29	5-5	5-5
3/4 1-3*	3/4 1-3	3/4 3-31	3/4 3-31	5-17	5-17
3/4 1-4*	3/4 1-4	3/4 3-31a	3/4 3-31a	5-18	5-18
3/4 1-5*	3/4 1-5	3/4 3-33	3/4 3-33	6-17	6-17
3/4 1-6*	3/4 1-6	3/4 3-34	3/4 3-34	6-22	6-22
3/4 1-8	3/4 1-8	-------	3/4 3-34a		
3/4 1-9	3/4 1-9	3/4 3-37	3/4 3-37		
3/4 1-10	3/4 1-10	3/4 4-7	3/4 4-7		
3/4 1-11	3/4 1-11	3/4 4-8	3/4 4-8		
3/4 1-12	3/4 1-12	3/4 4-18	3/4 4-18		
3/4 1-14	3/4 1-14	3/4 4-31	3/4 4-31		
3/4 1-14a	3/4 1-14a	3/4 4-32	3/4 4-32		
3/4 1-15	3/4 1-15	3/4 4-36	3/4 4-36		
3/4 2-16	3/4 2-16	3/4 5-2	3/4 5-2		
3/4 3-3	3/4 3-3	3/4 5-10	3/4 5-10		
3/4 3-4	3/4 3-4	3/4 6-6	3/4 6-6		

*By Letter dated March 15, 2012, FPL identified those COLR TS pages issued in Amendment Nos. 247 and 243 that supersede the EPU application TS pages.

FLORIDA POWER & LIGHT COMPANY

DOCKET NO. 50-250

TURKEY POINT NUCLEAR GENERATING UNIT NO. 3

RENEWED FACILITY OPERATING LICENSE NO. DPR-31

The U.S. Nuclear Regulatory Commission (the Commission) having previously made the findings set forth in License No. DPR-31 issued on July 19, 1972, has now found that:

a. The application to renew License No. DPR-31 filed by Florida Power and Light Company, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;

b. Actions have been identified and have been or will be taken with respect to (1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21(a)(1), and (2) time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c), such that there is reasonable assurance that the activities authorized by this renewed license will continue to be conducted in accordance with the current licensing basis, as defined in 10 CFR 54.3, for the Turkey Point Unit 3 plant, and that any changes made to the plant's current licensing basis in order to comply with 10 CFR 54.29(a) are in accord with the Act and the Commission's regulations;

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

d. There is reasonable assurance (i) that the facility can be operated at steady state power levels up to 2644 megawatts thermal in accordance with this renewed operating license without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission;

e. Florida Power and Light Company is technically and financially qualified to engage in the activities authorized by this renewed operating license in accordance with the rules and regulations of the Commission;

E. Pursuant to the Act and 10 CFR Parts 40 and 70 to receive, possess, and use at any time 100 milligrams each of any source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactively contaminated apparatus;

F. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of Turkey Point Units Nos. 3 and 4.

3. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect, and is subject to the additional conditions specified below:

A. Maximum Power Level

The applicant is authorized to operate the facility at reactor core power levels not in excess of 2644 megawatts (thermal).

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No249are hereby incorporated into this renewed license. The Environmental Protection Plan contained in Appendix B is hereby incorporated into this renewed license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

C. Final Safety Analysis Report

The licensee's Final Safety Analysis Report supplement submitted pursuant to 10 CFR 54.21(d), as revised on November 1, 2001, describes certain future inspection activities to be completed before the period of extended operation. The licensee shall complete these activities no later than July 19, 2012.

The Final Safety Analysis Report supplement as revised on November 1, 2001, described above, shall be included in the next scheduled update to the Final Safety Analysis Report required by 10 CFR 50.71(e)(4), following the issuance of this renewed license. Until that update is complete, the licensee may make changes to the programs described in such supplement without prior Commission approval, provided that the licensee evaluates each such change pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

3. The CREVS compensatory filtration unit, which is being installed by FPL as part of the AST methodology implementation at Turkey Point, will be designed in accordance with the Class I Structures, Systems, and Equipment Design Requirements defined in Appendix 5A of the Turkey Point UFSAR. As such, the compensatory filtration unit will be designed so that the stress limits found in Table 5A-1 of the Turkey Point UFSAR will not be exceeded due to the loadings imposed by a maximum hypothetical earthquake. FPL shall ensure that the design of the compensatory filtration unit satisfies these stress limits prior to the implementation of the proposed AST methodology at Turkey Point.

I. Control Room Habitability

Upon implementation of Amendment No. 248 adopting TSTF-448 Revision 3, the determination of control room envelope (CRE) unfiltered air inleakage as required by Surveillance Requirement (SR) 4.7.5.g, in accordance with Technical Specification (TS) 6.8.4.k.c.(i), the assessment of CRE habitability as required by Specification 6.8.4.k.c.(ii), and the measurement of CRE pressure as required by Specification 6.8.4.k.d, shall be considered met. Following implementation:

(a) The first performance of SR 4.7.5.g, in accordance with Specification 6.8.4.k.c.(i), shall be within the specified Frequency of 3 years, plus the 9-month allowance of SR 4.0.2, as measured from July 31, 2009, the date of the most recent tracer gas test.*

(b) The first performance of the periodic assessment of CRE habitability, Specification 6.8.4.k.c.(ii), shall be within 3 years, plus the 9-month allowance of SR 4.0.2, as measured from July 31,2009, the date of the most recent tracer gas test.

(c) The first performance of the periodic measurement of CRE pressure, Specification 6.8.4.k.d, shall be within 36 months on a STAGGERED TEST BASIS, plus the 138 days allowed by SR 4.0.2, as measured from the date of the most recent successful pressure measurement test, or within 138 days of license amendment implementation if not performed previously.

* *The most recent tracer gas test (July 31, 2009) was unsuccessful in that there was a measured 9 cfm control room inleakage: the acceptance criteria is 0 cfm. In accordance with Regulatory Guide (RG) 1.197 Rev. 0, a recalculation of the consequences to the control room operators was performed, and the results were acceptable for continued CREVS operability. Consistent with RG 1.197, a full test is to be conducted three years later to ascertain whether the CRE's integrity has continued to degrade.*

J. Extended Power Uprate Modifications

1. Prior to completion of the Cycle 26 refueling outage for Unit 3, the licensee shall provide confirmation to the NRC staff that the design and structural integrity evaluations associated with the modifications related to the spent fuel pool supplemental heat exchangers are complete, and that the results demonstrate compliance with appropriate UFSAR and code requirements. As part of the confirmation, the licensee shall provide a summary of the structural qualification results of the piping, pipe supports, supplemental heat exchanger supports, and the inter-tie connection with the existing heat exchanger for the appropriate load combinations along with the margins.

K. PAD TCD Safety Analyses

1. PAD 4.0 TCD has been specifically approved for use for the Turkey Point licensing basis analyses. Upon NRC's approval of a revised generic version of PAD that accounts for Thermal Conductivity Degradation (TCD), FPL will within six months:

   a. Demonstrate that PAD 4.0 TCD remains conservatively bounding in licensing basis analyses when compared to the new generically approved version of PAD w/TCD, or
   b. Provide a schedule for the re-analysis using the new generically approved version of PAD w/TCD for any of the affected licensing basis analyses.

L. Burnable Absorbers in Spent Fuel Pool

1. With respect to Technical Specification 5.5.1.3, FPL shall not credit any burnable absorber other than Integral Fuel Burnable Absorber (IFBA) rods for the storage of fuel assemblies in the Region I spent fuel racks.

4. This renewed license is effective as of the date of issuance, and shall expire at midnight July 19, 2032.

FOR THE NUCLEAR REGULATORY COMMISSION

Signed by
Samuel J. Collins, Director
Office of Nuclear Reactor Regulation

Attachments:
Appendix A – Technical Specifications for Unit 3
Appendix B – Environmental Protection Plan

Date of Issuance: June 6, 2002

FLORIDA POWER & LIGHT COMPANY

DOCKET NO. 50-251

TURKEY POINT NUCLEAR GENERATING UNIT NO. 4

RENEWED FACILITY OPERATING LICENSE NO. DPR-41

The U.S. Nuclear Regulatory Commission (the Commission) having previously made the findings set forth in License No. DPR-41 issued on April 10, 1973, has now found that:

a. The application to renew License No. DPR-41 filed by Florida Power and Light Company, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I and all required notifications to other agencies or bodies have been duly made;

b. Actions have been identified and have been or will be taken with respect to (1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under 10 CFR 54.21(a)(1), and (2) time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c), such that there is reasonable assurance that the activities authorized by this renewed license will continue to be conducted in accordance with the current licensing basis, as defined in 10 CFR 54.3, for the Turkey Point Unit 4 plant, and that any changes made to the plant's current licensing basis in order to comply with 10 CFR 54.29(a) are in accord with the Act and the Commission's regulations;

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

d. There is reasonable assurance (i) that the facility can be operated at steady state power levels up to 2644 megawatts thermal in accordance with this renewed operating license without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the rules and regulations of the Commission;

e. Florida Power and Light Company is technically and financially qualified to engage in the activities authorized by this renewed operating license in accordance with the rules and regulations of the Commission;

E. Pursuant to the Act and 10 CFR Parts 40 and 70 to receive, possess, and use at any time 100 milligrams each of any source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactively contaminated apparatus;

F. Pursuant to the Act and 10 CFR Parts 30 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of Turkey Point Units Nos. 3 and 4.

3. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect, and is subject to the additional conditions specified below:

A. Maximum Power Level

The applicant is authorized to operate the facility at reactor core power levels not in excess of 2644 megawatts (thermal).

B. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No245are hereby incorporated into this renewed license. The Environmental Protection Plan contained in Appendix B is hereby incorporated into this renewed license. The licensee shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

C. Final Safety Analysis Report

The licensee's Final Safety Analysis Report supplement submitted pursuant to 10 CFR 54.21(d), as revised on November 1, 2001, describes certain future inspection activities to be completed before the period of extended operation. The licensee shall complete these activities no later than April 10, 2013.

The Final Safety Analysis Report supplement as revised on November 1, 2001, described above, shall be included in the next scheduled update to the Final Safety Analysis Report required by 10 CFR 50.71(e)(4), following the issuance of this renewed license. Until that update is complete, the licensee may make changes to the programs described in such supplement without prior Commission approval, provided that the licensee evaluates each such change pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

(d) FPL will not move any fuel assemblies into the Unit 4 SFP subsequent to the successful completion of startup physics tests for Unit 4 Cycle 25.

I. Alternative Source Term Modifications

1. FPL will relocate the CR Ventilation System emergency air intakes prior to implementation of AST. The relocated intakes and associated ductwork will be designed to seismic criteria, protected from environmental effects, and will meet the requirements of 10 CFR 50 Appendix A, GDC 19. The new intakes will be located near the ground level extending out from the southeast and northeast corners of the auxiliary building and will fall within diverse wind sectors for post-accident contaminants. FPL will perform post-modification testing in accordance with the plant design modification procedures to ensure the TS pressurization flow remains adequate to demonstrate the integrity of the relocated intakes. In addition, FPL will provide to the NRC a confirmatory assessment which demonstrates that the requirements of 10 CFR 50 Appendix A, GDC 19 will be met. The confirmatory assessment will follow the methodology in Amendment 240 [the alternative source term amendment] including the methods used for the establishment of the atmospheric dispersion factors (X/Q values).

2. FPL will install ten (two large and eight small) stainless steel wire mesh baskets containing NaTB located in the containment basement to maintain pH during the sump recirculation phase following a Design Basis LOCA.

3. The CREVS compensatory filtration unit, which is being installed by FPL as part of the AST methodology implementation at Turkey Point will be designed in accordance with the Class I Structures, Systems, and Equipment Design Requirements defined in Appendix 5A of the Turkey Point UFSAR. As such, the compensatory filtration unit will be designed so that the stress limits found in Table 5A-1 of the Turkey Point UFSAR will not be exceeded due to the loadings imposed by a maximum hypothetical earthquake. FPL shall ensure that the design of the compensatory filtration unit satisfies these stress limits prior to the implementation of the proposed AST methodology at Turkey Point.

J. Control Room Habitability

Upon implementation of Amendment No. 244 adopting TSTF-448 Revision 3, the determination of control room envelope (CRE) unfiltered air inleakage as required by Surveillance Requirement (SR) 4.7.5.g, in accordance with Technical Specification (TS) 6.8.4.k.c.(i), the assessment of CRE habitability as required by Specification 6.8.4.k.c.(ii), and the measurement of CRE pressure as required by Specification 6.8.4.k.d, shall be considered met. Following implementation:

(a) The first performance of SR 4.7.5.g, in accordance with Specification 6.8.4.k.c.(i), shall be within the specified Frequency of 3 years, plus the 9-month

allowance of SR 4.0.2, as measured from July 31, 2009, the date of the most recent tracer gas test.*

(b) The first performance of the periodic assessment of CRE habitability, Specification 6.8.4.k.c.(ii), shall be within 3 years, plus the 9-month allowance of SR 4.0.2, as measured from July 31,2009, the date of the most recent tracer gas test.

(c) The first performance of the periodic measurement of CRE pressure, Specification 6.8.4.k.d, shall be within 36 months on a STAGGERED TEST BASIS, plus the 138 days allowed by SR 4.0.2, as measured from the date of the most recent successful pressure measurement test, or within 138 days of license amendment implementation if not performed previously.

* *The most recent tracer gas test (July 31, 2009) was unsuccessful in that there was a measured 9 cfm control room inleakage: the acceptance criteria is 0 cfm. In accordance with Regulatory Guide (RG) 1.197 Rev. 0, a recalculation of the consequences to the control room operators was performed, and the results were acceptable for continued CREVS operability. Consistent with RG 1.197, a full test is to be conducted three years later to ascertain whether the CRE's integrity has continued to degrade.*

K. Extended Power Uprate Modifications

1. Prior to completion of the Cycle 27 refueling outage for Unit 4, the licensee shall provide confirmation to the NRC staff that the design and structural integrity evaluations associated with the modifications related to the spent fuel pool supplemental heat exchangers are complete, and that the results demonstrate compliance with appropriate UFSAR and code requirements. As part of the confirmation, the licensee shall provide a summary of the structural qualification results of the piping, pipe supports, supplemental heat exchanger supports, and the inter-tie connection with the existing heat exchanger for the appropriate load combinations along with the margins.

L. PAD TCD Safety Analyses

1. PAD 4.0 TCD has been specifically approved for use for the Turkey Point licensing basis analyses. Upon NRC's approval of a revised generic version of PAD that accounts for Thermal Conductivity Degradation (TCD), FPL will within six months:

   a. Demonstrate that PAD 4.0 TCD remains conservatively bounding in licensing basis analyses when compared to the new generically approved version of PAD w/TCD, or
   b. Provide a schedule for the re-analysis using the new generically approved version of PAD w/TCD for any of the affected licensing basis analyses.

M. Burnable Absorbers in Spent Fuel Pool

1. With respect to Technical Specification 5.5.1.3, FPL shall not credit any burnable absorber other than Integral Fuel Burnable Absorber (IFBA) rods for the storage of fuel assemblies in the Region I spent fuel racks.

4. This renewed license is effective as of the date of issuance, and shall expire at midnight April 10, 2033.

FOR THE NUCLEAR REGULATORY COMMISSION

Signed by
Samuel J. Collins, Director
Office of Nuclear Reactor Regulation

Attachments:
Appendix A – Technical Specifications for Unit 4
Appendix B – Environmental Protection Plan

Date of Issuance: June 6, 2002

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

SECTION PAGE

INDEX

DESIGN FEATURES

QUADRANT POWER TILT RATIO

1.22 QUADRANT POWER TILT RATIO shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater. With one excore detector inoperable, the remaining three detectors shall be used for computing the average.

RATED THERMAL POWER

1.23 RATED THERMAL POWER shall be a total reactor core heat transfer rate to the reactor coolant of 2644 MWt.

REPORTABLE EVENT

1.24 A REPORTABLE EVENT shall be any of those conditions specified in Section 50.73 of 10 CFR Part 50.

SHUTDOWN MARGIN

1.25 SHUTDOWN MARGIN shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming all full-length rod cluster assemblies (shutdown and control) are fully inserted except for the single rod cluster assembly of highest reactivity worth which is assumed to be fully withdrawn.

SITE BOUNDARY

1.26 The SITE BOUNDARY shall mean that line beyond which the land or property is not owned, leased, or otherwise controlled by the licensee.

SOLIDIFICATION

1.27 SOLIDIFICATION shall be the conversion of wet wastes into a form that meets shipping and burial ground requirements.

SOURCE CHECK

1.28 A SOURCE CHECK shall be the qualitative assessment of channel response when the channel sensor is exposed to a source of increased radioactivity.

STAGGERED TEST BASIS

1.29 A STAGGERED TEST BASIS shall consist of:

a. A test schedule for n systems, subsystems, trains, or other designated components obtained by dividing the specified test interval into n equal subintervals, and

b. The testing of one system, subsystem, train, or other designated component at the beginning of each subinterval.

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TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
1. Manual Reactor Trip	N.A.	N.A.
2. Power Range, Neutron Flux		
a. High Setpoint	$\leq$ 108.6% of RTP**	108.0% of RTP**
b. Low Setpoint	$\leq$ 28.0% of RTP**	$\leq$ 25% of RTP**
3. Intermediate Range, Neutron Flux	$\leq$ 31.0% of RTP**	$\leq$ 25% of RTP**
4. Source Range, Neutron Flux	$\leq 1.4 \times 10^5$ cps	$\leq 10^5$ cps
5. Overtemperature ΔT	See Note 2	See Note 1
6. Overpower ΔT	See Note 4	See Note 3
7. Pressurizer Pressure-Low	$\geq$ 1817 psig	$\geq$ 1835 psig
8. Pressurizer Pressure-High	$\leq$ 2403 psig	$\leq$ 2385 psig
9. Pressurizer Water Level-High	$\leq$ 92.2% of instrument span	$\leq$ 92% of instrument span
10. Reactor Coolant Flow-Low	$\geq$ 89.6% of loop design flow*	90% of loop design flow*
11. Steam Generator Water Level Low-Low	$\geq$ 15.5% of narrow range instrument span	16% of narrow range instrument span

* Loop design flow = 86,900 gpm

** RTP = Rated Thermal Power

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
12. Steam/Feedwater Flow Mismatch Coincident with	Feed Flow ≤ 20.7% below rated Steam Flow	Feed Flow 20% below rated Steam Flow
Steam Generator Water Level-Low	≥ 15.5% of narrow range instrument span	16% of narrow range instrument span
13. Undervoltage – 4.16 kV Busses A and B	≥ 69% bus voltage	≥ 70% bus voltage
14. Underfrequency – Trip of Reactor Coolant Pump Breaker(s) Open	≥ 55.9 Hz	≥ 56.1 Hz
15. Turbine Trip		
a. Emergency Trip Header Pressure	≥ 901 psig	1000 psig
b. Turbine Stop Valve Closure	Fully Closed***	Fully Closed***
16. Safety Injection Input from ESF	N.A.	N.A.
17. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	$\geq 6.0 \times 10^{-11}$ amps	Nominal 1×10^{-10} amps

*** Limit switch is set when Turbine Stop Valves are fully closed.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
b. Low Power Reactor Trips Block, P-7		
1) P-10 input	≤ 13.0% RTP**	Nominal 10% of RTP**
2) Turbine Inlet Pressure	≤ 13.0% Turbine Power	Nominal 10% Turbine Power |
c. Power Range Neutron Flux, P-8	≤ 48.0% RTP**	Nominal 45% of RTP**
d. Power Range Neutron Flux, P-10	≥ 7.0% RTP**	Nominal 10% of RTP**
18. Reactor Coolant Pump Breaker Position Trip	N.A.	N.A.
19. Reactor Trip Breakers	N.A.	N.A.
20. Automatic Trip and Interlock Logic	N.A.	N.A.

** RTP = RATED THERMAL POWER

TABLE 2.2-1 (Continued)
TABLE NOTATIONS

NOTE 1: OVERTEMPERATURE ΔT (Those values denoted with [*] are specified in the COLR.)

$$\Delta T \quad \frac{(1+\tau_1 S)}{(1+\tau_2 S)}\left(\frac{1}{1+\tau_3 S}\right) \le \Delta T_0 \left\{K_1 - K_2 \frac{(1+\tau_4 S)}{(1+\tau_5 S)}\left[T \frac{1}{(1+\tau_6 S)} - T'\right] + K_3(P - P') - f_1(\Delta I)\right\}$$

Where: ΔT = Measured ΔT by RTD Instrumentation

$\frac{1+\tau_1 S}{1+\tau_2 S}$ = Lead/Lag compensator on measured ΔT; τ_1 = [*]s, τ_2 = [*]s

$\frac{1}{1+\tau_3 S}$ = Lag compensator on measured ΔT; τ_3 = [*]s

ΔT_0 = Indicated ΔT at RATED THERMAL POWER

K_1 = [*];

K_2 = [*]/°F;

$\frac{1+\tau_4 S}{1+\tau_5 S}$ = The function generated by the lead-lag compensator for T_{avg} dynamic compensation;

τ_4 , τ_5 = Time constants utilized in the lead-lag compensator for T_{avg}, τ_4 = [*]s, τ_5 = [*]s;

T = Average temperature, °F;

$\frac{1}{1+\tau_6 S}$ = Lag compensator on measured T_{avg}; τ_6 = [*]s

T' $\le$ [*]°F (Indicated Loop T_{avg} at RATED THERMAL POWER);

K_3 = [*]/psi;

P = Pressurizer pressure, psig;

TABLE 2.2-1 (Continued)

TABLE NOTATIONS (Continued)

NOTE 1: (Continued)

P' ≥ [*] psig (Nominal RCS operating pressure);

S = Laplace transform operator, s^{-1};

And $f_1(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range neutron ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(1) For $q_t - q_b$ between – [*]% and + [*]%, $f_1(\Delta I) = 0$, where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER;

(2) For each percent that the magnitude of $q_t - q_b$ exceeds – [*]%, the ΔT Trip Setpoint shall be automatically reduced by [*]% of its value at RATED THERMAL POWER; and

(3) For each percent that the magnitude of $q_t - q_b$ exceeds + [*]%, the ΔT Trip Setpoint shall be automatically reduced by [*]% of its value at RATED THERMAL POWER.

NOTE 2: The Overtemperature ΔT function Allowable Value shall not exceed the nominal trip setpoint by more than 0.5% ΔT span for the ΔT channel, 0.2% ΔT span for the Pressurizer Pressure channel, and 0.4% ΔT span for the f(ΔI) channel. No separate Allowable Value is provided for T_{avg} because this function is part of the ΔT value.

TABLE 2.2-1 (Continued)

TABLE NOTATIONS (Continued)

NOTE 3: OVERPOWER ΔT (Those values denoted with [*] are specified in the COLR.)

$$\Delta T \frac{(1+\tau_1 S)}{(1+\tau_2 S)} \left(\frac{1}{1+\tau_3 S}\right) \leq \Delta T_0 \left\{K_4 - K_5 \frac{\tau_7 S}{1+\tau_7 S} \left(\frac{1}{1+\tau_6 S}\right) T - K_6 \left[T \frac{1}{1+\tau_6 S} - T''\right] - f_2(\Delta I)\right\}$$

Where: ΔT = As defined in Note 1,

$\frac{1+\tau_1 S}{1+\tau_2 S}$ = As defined in Note 1,

$\frac{1}{1+\tau_3 S}$ = As defined in Note 1,

ΔT_0 = As defined in Note 1,

K_4 = [*],

K_5 ≥ [*]/°F for increasing average temperature and [*]/°F for decreasing average temperature,

$\frac{\tau_7 s}{1+\tau_7 S}$ = The function generated by the lead-lag compensator for T_{avg} dynamic compensation;

τ_7 = Time constants utilized in the lead-lag compensator for T_{avg}, $\tau_7 \geq$ [*] s,

$\frac{1}{1+\tau_6 S}$ = As defined in Note 1,

TABLE 2.2-1 (Continued)

TABLE NOTATIONS (Continued)

NOTE 3: (Continued)

K_6 = [*]/°F for T > T"

= [*] for T ≤ T",

T = As defined in Note 1,

T" ≤ [*]°F (Indicated Loop T_{avg} at RATED THERMAL POWER)

S = As defined in Note 1, and

f_2 (ΔI) = [*]

NOTE 4: The Overpower ΔT function Allowable Value shall not exceed the nominal trip setpoint by more than 0.5% ΔT span for the ΔT channel. No separate Allowable Value is provided for T_{avg} because this function is part of the ΔT value.

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SHUTDOWN MARGIN - T_{avg} LESS THAN OR EQUAL TO 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.2 The SHUTDOWN MARGIN shall be within the limit specified in the COLR.

APPLICABILITY: MODE 5.

ACTION:

With the SHUTDOWN MARGIN not within limits, immediately initiate and continue boration at greater than or equal to 16 gpm of a solution containing greater than or equal to 3.0 wt% (5245 ppm) boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN shall be determined to be shall be within the limit specified in the COLR:

a. Within 1 hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s); and

b. At least once per 24 hours by consideration of the following factors:

    1) Reactor Coolant System boron concentration,

    2) Control rod position,

    3) Reactor Coolant System average temperature,

    4) Fuel burnup based on gross thermal energy generation,

    5) Xenon concentration, and

    6) Samarium concentration.

REACTIVITY CONTROL SYSTEMS

MODERATOR TEMPERATURE COEFFICIENT

LIMITING CONDITION FOR OPERATION

3.1.1.3 The moderator temperature coefficient (MTC) shall be within the limits specified in the COLR. The maximum upper limit shall be less positive than or equal to $+5.0 \times 10^{-5}$ $\Delta k/k/°F$ for all the rods withdrawn, beginning of cycle life (BOL), for power levels up to 70% RATED THERMAL POWER with a linear ramp to 0 $\Delta k/k/°F$ at 100 % RATED THERMAL POWER.

APPLICABILITY: Beginning of cycle life (BOL) - MODES 1 and 2* only**.
End of cycle life (EOL) - MODES 1, 2, and 3 only**.

ACTION:

a. With the MTC more positive than the BOL limit specified in the COLR, operation in MODES 1 and 2 may proceed provided:

1. Control rod withdrawal limits are established and maintained sufficient to restore the MTC to less positive or equal to the BOL limit specified in the COLR within 24 hours or be in HOT STANDBY within the next 6 hours. These withdrawal limits shall be in addition to the insertion limits of Specification 3.1.3.6;

2. The control rods are maintained within the withdrawal limits established above until a subsequent calculation verifies that the MTC has been restored to within its limit for the all rods withdrawn condition; and

3. A Special Report is prepared and submitted to the Commission, pursuant to Specification 6.9.2, within 10 days, describing the value of the measured MTC, the interim control rod withdrawal limits, and the predicted average core burnup necessary for restoring the positive MTC to within its limit for the all rods withdrawn condition.

---

* With K_{eff} greater than or equal to 1.

** See Special Test Exceptions Specification 3.10.3.

LIMITING CONDITION FOR OPERATION

ACTION: (Continued)

b. With the MTC more negative than the EOL limit specified in the COLR, be in HOT SHUTDOWN within 12 hours.

SURVEILLANCE REQUIREMENTS

4.1.1.3 The MTC shall be determined to be within its limits during each fuel cycle as follows:

a. The MTC shall be measured and compared to the BOL limit specified in the COLR, prior to initial operation above 5% of RATED THERMAL POWER, after each fuel loading; and

b. The MTC shall be measured at any THERMAL POWER and compared to the 300 ppm surveillance limit specified in the COLR (all rods withdrawn, RATED THERMAL POWER condition) within 7 EFPD after reaching an equilibrium boron concentration of 300 ppm. In the event this comparison indicates the MTC is more negative than the 300 ppm surveillance limit specified in the COLR, the MTC shall be remeasured, and compared to the EOL MTC limit specified in the COLR, at least once per 14 EFPD during the remainder of the fuel cycle.

3/4.1.2 BORATION SYSTEMS

FLOW PATH - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths shall be OPERABLE and capable of being powered from an OPERABLE emergency power source:

a. A flow path from the boric acid storage tanks via a boric acid transfer pump and a charging pump to the Reactor Coolant System if the boric acid storage tank in Specification 3.1.2.4a. is OPERABLE, or

b. The flow path from the refueling water storage tank via a charging pump to the Reactor Coolant System if the refueling water storage tank in Specification 3.1.2.4b. is OPERABLE.

APPLICABILITY: MODES 5 and 6.

ACTION:

With none of the above flow paths OPERABLE or capable of being powered from an OPERABLE emergency power source, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that the temperature of the rooms containing flow path components is greater than or equal to 62°F when a flow path from the boric acid tanks is used, and

b. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

REACTIVITY CONTROL SYSTEMS

FLOW PATHS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.2 The following boron injection flow paths shall be OPERABLE:

a. The source path from a boric acid storage tank via a boric acid transfer pump to the charging pump suction*, and

b. At least one of the two source paths from the refueling water storage tank to the charging pump suction; and,

c. The flow path from the charging pump discharge to the Reactor Coolant System via the regenerative heat exchanger.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With no boration source path from a boric acid storage tank OPERABLE,

   1. Demonstrate the OPERABILITY of the second source path from the refueling water storage tank to the charging pump suction by verifying the flow path valve alignment; and

   2. Restore the boration source path from a boric acid storage tank to OPERABLE status within 70 hours or be in at least HOT STANDBY and borated to a boron concentration equivalent to at least the required SHUTDOWN MARGIN at COLD SHUTDOWN at 200°F within the next 8 hours; restore the boration source path from a boric acid storage tank to OPERABLE status within the next 72 hours or be in COLD SHUTDOWN within the next 30 hours.

b. With only one boration source path OPERABLE or the regenerative heat exchanger flow path to the RCS inoperable, restore the required flow paths to OPERABLE status within 70 hours or be in at least HOT STANDBY and borated to a boron concentration equivalent to at least the required SHUTDOWN MARGIN at COLD SHUTDOWN at 200°F within the next 8 hours; restore at least two boration source paths to OPERABLE status within the next 72 hours or be in COLD SHUTDOWN within the next 30 hours.

c. With the boration source path from a boric acid storage tank and the charging pump discharge path via the regenerative heat exchanger inoperable, within one hour initiate boration to a boron concentration equivalent to the required SHUTDOWN MARGIN at COLD SHUTDOWN at 200°F and go to COLD SHUTDOWN as soon as possible within the limitations of the boration and pressurizer level control functions of the CVCS.

* The flow required in Specification 3.1.2.2.a above shall be isolated from the other unit from the boric acid transfer pump discharge to the charging pump suction.

SURVEILLANCE REQUIREMENTS

4.1.2.2 The above required flow paths shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that the temperature of the rooms containing flow path components is greater than or equal to 62°F when a flow path from the boric acid tanks is used; |

b. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position;

c. At least once per 18 months by verifying that the flow path required by Specification 3.1.2.2a. and c. delivers at least 16 gpm to the RCS.

CHARGING PUMPS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.3 At least two charging pumps shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With only one charging pump OPERABLE, restore at least two charging pumps to OPERABLE status within 70 hours or be in at least HOT STANDBY and borated to a boron concentration equivalent to at least the required SHUTDOWN MARGIN at COLD SHUTDOWN at 200°F within 8 hours; restore at least two charging pumps to OPERABLE status within 72 hours or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.3.1 The required charging pumps shall be demonstrated OPERABLE by testing pursuant to Specification 4.0.5. The provisions of Specification 4.0.4 are not applicable for entry into MODES 3 and 4.

REACTIVITY CONTROL SYSTEMS

BORATED WATER SOURCE - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.4 As a minimum, one of the following borated water sources shall be OPERABLE:

a. A Boric Acid Storage System with:

1) A minimum indicated borated water volume of 2,900 gallons per unit,

2) A boron concentration between 3.0 wt% (5245 ppm) and 4.0 wt.% (6993 ppm), and

3) A minimum boric acid tanks room temperature of 62°F.

b. The refueling water storage tank (RWST) with:

1) A minimum indicated borated water volume of 20,000 gallons,

2) A boron concentration between 2400 ppm and 2600 ppm, and

3) A minimum solution temperature of 39°F.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no borated water source OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.4 The above required borated water source shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1) Verifying the boron concentration of the water,

2) Verifying the indicated borated water volume, and

3) Verifying that the temperature of the boric acid tanks room is greater than or equal to 62°F, when it is the source of borated water.

REACTIVITY CONTROL SYSTEMS

BORATED WATER SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.5 The following borated water sources shall be OPERABLE:

a. A Boric Acid Storage System with:

1) A minimum indicated borated water volume in accordance with Figure 3.1-2,

2) A boron concentration in accordance with Figure 3.1-2. and

3) A minimum boric acid tanks room temperature of 62°F.

b. The refueling water storage tank (RWST) with:

1) A minimum indicated borated water volume of 320,000 gallons,

2) A boron concentration between 2400 ppm and 2600 ppm.

3) A minimum solution temperature of 39°F, and

4) A maximum solution temperature of 100°F.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

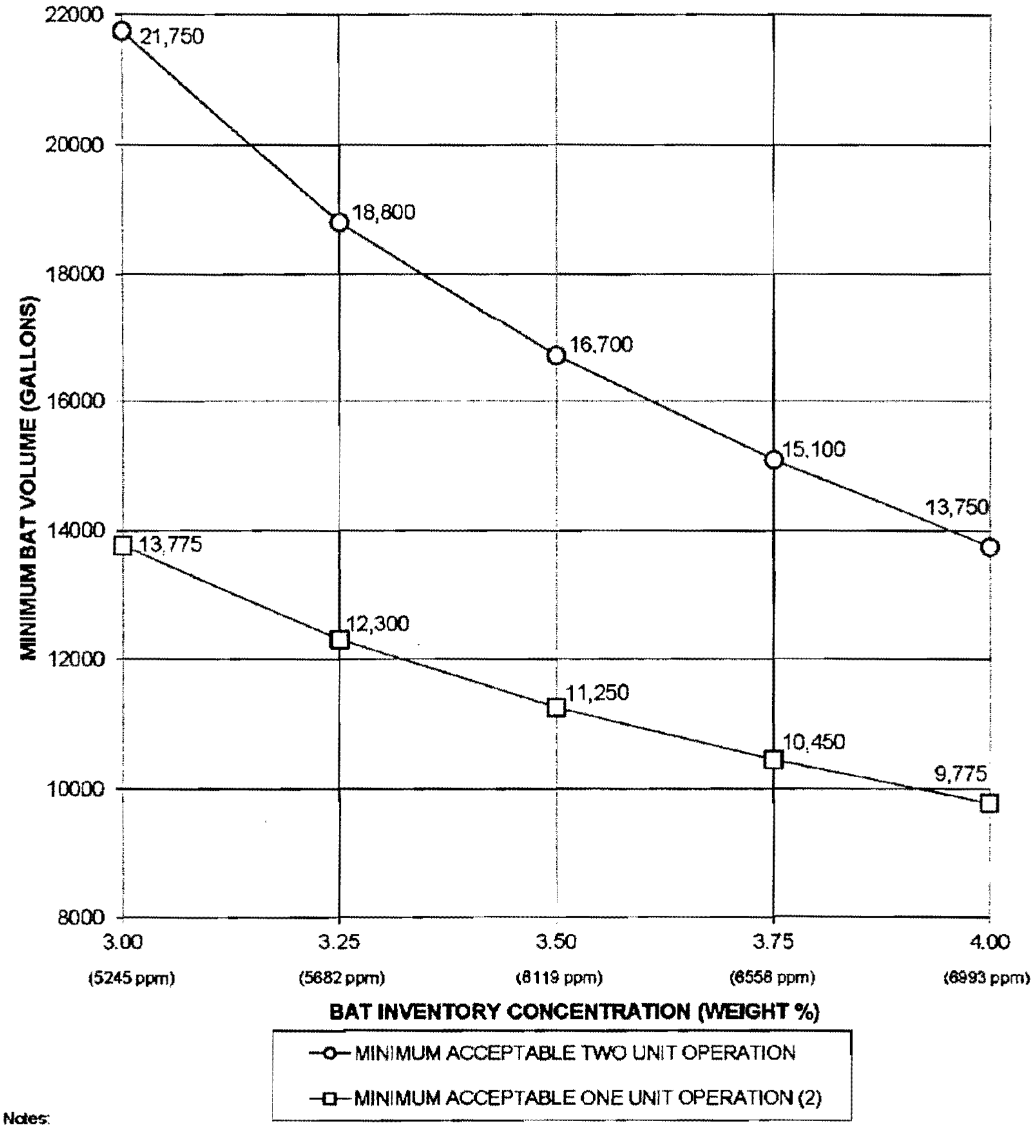
a. With the required Boric Acid Storage System inoperable verify that the RWST is OPERABLE; restore the system to OPERABLE status within 70 hours or be in at least HOT STANDBY within the next 8 hours* and borated to a boron concentration equivalent to at least the required SHUTDOWN MARGIN at COLD SHUTDOWN at 200°F; restore the Boric Acid Storage System to OPERABLE status within the next 72 hours or be in COLD SHUTDOWN within the next 30 hours.

b. With the RWST inoperable, restore the tank to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With the boric acid tank inventory concentration greater than 4.0 wt%, verify that the boric acid solution temperature for boration sources and flow paths is greater than the solubility limit for the concentration.

* If this action applies to both units simultaneously, be in at least HOT STANDBY within the next sixteen hours.

Figure 3.1-2
BORIC ACID TANK MINIMUM VOLUME (1)
Modes 1, 2, 3 and 4



Notes:

(1) Combined volume of all available boric acid tanks assuming RWST boron concentration between 2400 ppm and 2600 ppm.
(2) Includes 2900 gallons for the shutdown unit.

SURVEILLANCE REQUIREMENTS

4.1.2.5 Each borated water source shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1) Verifying the boron concentration in the water,

2) Verifying the indicated borated water volume of the water source, and

3) Verifying that the temperature of the boric acid tanks room is greater than or equal to 62°F, when it is the source of borated water.

b. By verifying the RWST temperature is within limits whenever the outside air temperature is less than 39°F or greater than 100°F at the following frequencies:

1) Within one hour upon the outside temperature exceeding its limit for 23 consecutive hours, and

2) At least once per 24 hours while the outside temperature exceeds its limits.

3/4.2.5 DNB PARAMETERS

LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB-related parameters shall be maintained within the following limits:

a. Reactor Coolant System T_{avg} is less than or equal to the limit specified in the COLR

b. Pressurizer Pressure is greater than or equal to the limit specified in the COLR*, and

c. Reactor Coolant System Flow ≥ 270,000 gpm

APPLICABILITY: MODE 1.

ACTION:

With any of the above parameters exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less then 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5.1 Reactor Coolant System T_{avg} and Pressurizer Pressure shall be verified to be within their limits at least once per 12 hours.

4.2.5.2 RCS flow rate shall be monitored for degradation at least once per 12 hours.

4.2.5.3 The RCS flow rate indicators shall be subjected to a CHANNEL CALIBRATION at least once per 18 months.

4.2.5.4 After each fuel loading, and at least once per 18 months, the RCS flow rate shall be determined by precision heat balance after exceeding 90% RATED THERMAL POWER. The measurement instrumentation shall be calibrated within 90 days prior to the performance of the calorimetric flow measurement. The provisions of 4.0.4 are not applicable for performing the precision heat balance flow measurement.

* Limit not applicable during either a THERMAL POWER ramp in excess of 5% of RATED THERMAL POWER per minute or a THERMAL POWER step in excess of 10% of RATED THERMAL POWER.

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
11. Steam Generator Water Level--Low-Low	3/stm. gen.	2/stm. gen.	2/stm. gen.	1, 2	6
12. Steam Generator Water Level--Low Coincident With Steam/ Feedwater Flow Mismatch	2 stm. gen. level and 2 stm./feed-water flow mismatch in each stm. gen.	1 stm. gen. level coin-cident with 1 stm./feed-water flow mismatch in same stm. gen.	1 stm. gen. level and 2 stm./feed-water flow mismatch in same stm. gen. or 2 stm. gen. level and 1 stm./feedwater flow mismatch in same stm. gen.	1, 2	6
13. Undervoltage--4.16 KV Busses A and B (Above P-7)	2/bus	1/bus on both busses	2/bus	1	12
14. Underfrequency-Trip of Reactor Coolant Pump Breaker(s) Open (Above P-7)	2/bus	1 to trip RCPs***	2/bus	1	11
15. Turbine Trip (Above P-7)					
a. Emergency Trip Header Pressure	3	2	2	1	12
b. Turbine Stop Valve Closure	2	2	2	1	12

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
16. Safety Injection Input from ESF	2	1	2	1, 2	8
17. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2	1	2	2#	7
b. Low Power Reactor Trips Block, P-7					
P-10 Input	4	2	3	1	7
or					
Turbine Inlet Pressure	2	1	2	1	7
c. Power Range Neutron Flux, P-8	4	2	3	1	7
d. Power Range Neutron Flux, P-10	4	2	3	1, 2	7
18. Reactor Coolant Pump Breaker Position Trip					
a. Above P-8	1/breaker	1	1/breaker	1	11
b. Above P-7 and below P-8	1/breaker	2	1/breaker	1	11
19. Reactor Trip Breakers	2	1	2	1, 2	8, 10
	2	1	2	3*, 4*, 5*	9
20. Automatic Trip and Interlock logic	2	1	2	1, 2	8
	2	1	2	3*, 4*, 5*	9

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	N.A.	R(11)	N.A.	1, 2, 3*, 4*, 5*
2. Power Range, Neutron Flux						
a. High Setpoint	S	D(2, 4), M(3, 4), Q(4, 6),[(a), (b)] R(4)[(a), (b)]	Q[(a), (b)]	N.A.	N.A.	1, 2
b. Low Setpoint	S	R(4)	S/U(1)	N.A.	N.A.	1***, 2
3. Intermediate Range, Neutron Flux	S	R(4)	S/U(1)	N.A.	N.A.	1***, 2
4. Source Range, Neutron Flux	S	R(4)	S/U(1), Q(9)	N.A.	N.A.	2**,3, 4, 5
5. Overtemperature ΔT	S	R[(a), (b)]	Q[(a), (b)]	N.A.	N.A.	1, 2
6. Overpower ΔT	S	R[(a), (b)]	Q[(a), (b)]	N.A.	N.A.	1, 2
7. Pressurizer Pressure--Low	S	R	Q	N.A.	N.A.	1
8. Pressurizer Pressure--High	S	R	Q	N.A.	N.A.	1, 2
9. Pressurizer Water Level--High	S	R	Q	N.A.	N.A.	1
10. Reactor Coolant Flow--Low	S	R[(a), (b)]	Q[(a), (b)]	N.A.	N.A.	1
11. Steam Generator Water Level--Low-Low	S	R[(a), (b)]	Q[(a), (b)]	N.A.	N.A.	1, 2

TABLE 4.3-1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
12. Steam Generator Water Level--Low Coincident with Steam/Feedwater Flow Mismatch	S	$R^{(a),(b)}$	$Q^{(a),(b)}$	N.A.	N.A.	1, 2
13. Undervoltage – 4.16 kV Busses A and B	N.A.	R	N.A.	N.A.	N.A.	1
14. Underfrequency – Trip of Reactor Coolant Pump Breakers(s) Open	N.A.	R	N.A.	N.A.	N.A.	1
15. Turbine Trip						
a. Emergency Trip Header Pressure	N.A.	$R^{(a),(b)}$	N.A.	S/U(1, 10)	N.A.	1
b. Turbine Stop Valve Closure	N.A.	R	N.A.	S/U(1, 10)	N.A.	1
16. Safety Injection Input from ESF	N.A.	N.A.	N.A.	R	N.A.	1, 2
17. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	N.A.	R(4)	R	N.A.	N.A.	2**
b. Low Power Reactor Trips Block, P-7 (includes P-10 input and Turbine Inlet Pressure)	N.A.	R(4)	R	N.A.	N.A.	1
c. Power Range Neutron Flux, P-8	N.A.	R(4)	R	N.A.	N.A.	1

TABLE 4.3-1 (Continued)

TABLE NOTATIONS

* When the Reactor Trip System breakers are closed and the Control Rod Drive System is capable of rod withdrawal.

** Below P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

*** Below P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

(a) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(b) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Nominal Trip Setpoint (NTS) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the NTS are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the surveillance procedures (field settings) to confirm channel performance. The NTS and methodologies used to determine the as-found and the as-left tolerances are specified in UFSAR Section 7.2.

(1) If not performed in previous 31 days.

(2) Comparison of calorimetric to excore power level indication above 15% of RATED THERMAL POWER (RTP). Adjust excore channel gains consistent with calorimetric power level if the absolute difference is greater than 2%. Below 70% RTP, downward adjustments of NIS excore channel gains to match a lower calorimetric power level are not required. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(3) Single point comparison of incore to excore AXIAL FLUX DIFFERENCE above 15% of RATED THERMAL POWER. Recalibrate if the absolute difference is greater than or equal to 3%. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(4) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(5) This table Notation number is not used.

(6) Incore-Excore Calibration, above 75% of RATED THERMAL POWER (RTP). If the quarterly surveillance requirement coincides with sustained operation between 30% and 75% of RTP, calibration shall be performed at this lower power level. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(7) Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(8) DELETED

(9) Quarterly surveillance in MODES 3*, 4*, and 5* shall also include verification that permissive P-6 and P-10 are in their required state for existing plant conditions by observation of the permissive annunciator window. Quarterly surveillance shall include verification of the High Flux at Shutdown Alarm Setpoint of 1/2 decade above the existing count rate.

(10) Setpoint verification is not applicable.

(11) The TRIP ACTUATING DEVICE OPERATIONAL TEST shall include independent verification of the OPERABILITY of the undervoltage and shunt trip attachment of the Reactor Trip Breakers.

TABLE 3.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Safety Injection					
a. Manual Initiation	2	1	2	1 2, 3, 4	17
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1 2, 3, 4	14
c. Containment Pressure - High	3	2	2	1 2, 3	15
d. Pressurizer Pressure - Low	3	2	2	1 2, 3#	15
e. High Differential Pressure Between the Steam Line Header and any Steam Line	3/steam line	2/steam line in any steam line	2/steam line	1 2, 3#	15

TABLE 3.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
4. Steam Line Isolation (Continued)					
d. Steam Line Flow--High Coincident with: Steam Generator Pressure--Low	2/steam line	1/steam line in any two steam lines	1/steam line in any two steam lines	1, 2, 3	15
	1/steam generator	1/steam generator in any two steam lines	1/steam generator in any two steam lines	1, 2, 3	15
or T_{avg}--Low	1/Loop	1/loop in any two loops	1/loop in any two loops	1, 2, 3	25
5. Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3	22
b. Safety-Injection	See Item 1. above for all Safety Injection initiating functions and requirements.				
c. Steam Generator Water Level -- High-High####	3/steam generator	2/steam generator in any operating steam generator	2/steam generator in any operating steam generator	1, 2, 3	15
6. Auxiliary Feedwater###					
a. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3	20

TABLE 3.3-3
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM
INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
1. Safety Injection		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic	N.A	N.A
c. Containment Pressure--High	≤4.5 psig	≤4.0 psig
d. Pressurizer Pressure--Low	≥1712 psig	≥1730 psig
e. High Differential Pressure Between the Steam Line Header and any Steam Line.	≤114 psig	≤100 psi
f. Steam Line Flow--High	≤A function defined as follows: A ΔP corresponding to 41.2% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 114.4% steam flow at full load	A function defined as follows: A ΔP corresponding to 40% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 114% steam flow at full load

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM
INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
Coincident with: Steam Generator Pressure--Low(4)	≥607 psig	614 psig
or T_{avg}--Low	≥542.5°F	≥543°F
2. Containment Spray		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Containment Pressure--High-High Coincident with:	≤22.6 psig	≤20.0 psig
Containment Pressure--High	≤4.5 psig	≤4.0 psig
3. Containment Isolation		
a. Phase "A" Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1 above for all Safety Injection Allowable Values.	See Item 1 above for all Safety Injection Trip Setpoints.
b. Phase "B" Isolation		
1) Manual Initiation	N.A.	N.A.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM
INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
4. Steam Line Isolation (Continued)		
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure--High-High Coincident with:	≤22.6 psig	≤20. psig
Containment Pressure--High	≤ 4.5 psig	≤4.0 psig
d. Steam Line Flow--High	≤A function defined as follows: A ΔP corresponding to 41.2% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 114.4% steam flow at full load.	A function defined as follows: A ΔP corresponding to 40% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 114% steam flow at full load.
Coincident with: Steam Line Pressure--Low(4)	≥607 psig	614 psig
or		
T_{avg} -- Low	≥542.5°F	≥543°F
5. Feedwater Isolation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Safety Injection	See Item 1. for all Safety Injection Allowable Valves.	See Item 1. above for all Safety Injection Trip Setpoints.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM
INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE	TRIP SETPOINT
5. Feedwater Isolation (Continued)		
c. Steam Generator Water Level High-High	≤80.5% of narrow range instrument span	80% of narrow range instrument span
6. Auxiliary Feedwater (3)		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Steam Generator Water Level–Low-Low	≥15.5% of narrow range instrument span.	16% of narrow range instrument span
c. Safety Injection	See Item 1. for all Safety Injection Allowable Values.	See Item 1. above for all Safety Injection Trip Setpoints.
d. Bus Stripping	See Item 7. below for all Bus Stripping Allowable Values.	See Item 7. below for all Bus Stripping Trip Setpoints.
e. Trip of All Main Feedwater Pump Breakers	N.A.	N.A.
7. Loss of Power		
a. 4.16 kV Busses A and B (Loss of Voltage)	N.A.	N.A.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM
INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE#	TRIP SETPOINT
7. Loss of Power (Continued)		
b. 480V Load Centers Undervoltage		
Load Center		
3A	[ ]	430V ±3V (10 sec ±1 sec delay)
3B	[ ]	438V ±3V (10 sec ±1 sec delay)
3C	[ ]	434V ±3V (10 sec ±1 sec delay)
3D	[ ]	434V ±3V (10 sec ±1 sec delay)
4A	[ ]	435V ±3V (10 sec ±1 sec delay)
4B	[ ]	434V ±3V (10 sec ±1 sec delay)
4C	[ ]	434V ±3V (10 sec ±1 sec delay)
4D	[ ]	430V ±3V (10 sec ±1 sec delay)
Coincident with: Safety Injection and	See Item 1. above for all Safety Injection Allowable Values.	See Item 1. above for all Safety Injection Trip Setpoints.
Diesel Generator Breaker Open	N.A.	N.A.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM
INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	ALLOWABLE VALUE#	TRIP SETPOINT
7. Loss of Power (Continued)		
c. 480V Load Centers Degraded Voltage		
Load Center		
3A	[ ]	424V ±3V (60 sec ±30 sec delay)
3B	[ ]	427V ±3V (60 sec ±30 sec delay)
3C	[ ]	437V ±3V (60 sec ±30 sec delay)
3D	[ ]	435V ±3V (60 sec ±30 sec delay)
4A	[ ]	430V ±3V (60 sec ±30 sec delay)
4B	[ ]	436V ±3V (60 sec ±30 sec delay)
4C	[ ]	434V ±3V (60 sec ±30 sec delay)
4D	[ ]	434V ±3V (60 sec ±30 sec delay)
Coincident with: Diesel Generator Breaker Open	N.A.	N.A.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM
INSTRUMENTATION TRIP SETPOINTS

TABLE NOTATIONS

(1) Either the particulate or gaseous channel in the OPERABLE status will satisfy this LCO.

(2) Containment Gaseous Monitor Setpoint = $\frac{(3.2 \times 10^4)}{(\quad F \quad)}$CPM,

Containment Gaseous Monitor Allowable Value = $\frac{(3.5 \times 10^4)}{(\quad F \quad)}$CPM,

Where F = $\frac{\text{Actual Purge Flow}}{\text{Design Purge Flow (35,000 CFM)}}$

Setpoint may vary according to current plant conditions provided that the release rate does not exceed allowable limits provided in the Offsite Dose Calculation Manual.

(3) Auxiliary feedwater manual initiation is included in Specification 3.7.1.2.

(4) Time constants utilized in lead-lag controller for Steam Generator Pressure-Low and Steam Line Pressure-Low are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds. CHANNEL CALIBRATION shall ensure that these time constants are adjusted to these values.

If no Allowable Value is specified, as indicated by [ ], the trip setpoint shall also be the allowable value.

TABLE 4.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST #	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Safety Injection						
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	1, 2, 3
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	1, 2, 3(3)
c. Containment Pressure--High	N.A.	R	N.A.	N.A.	M(1)	1, 2, 3
d. Pressurizer Pressure--Low	S	R	Q(5)	N.A.	N.A.	1, 2, 3(3)
e. High Differential Pressure Between the Steam Line Header and any Steam Line	S	R	Q(5)	N.A.	N.A.	1, 2, 3(3)
f. Steam Line Flow--High Coincident with:	S	R[(a)(b)]	Q(5)[(a)(b)]	N.A	N.A	1, 2, 3(3)
Steam Generator Pressure--Low	S	R[(a)(b)]	Q(5)[(a)(b)]	N.A.	N.A.	1, 2, 3(3)
or						
Tavg--Low	S	R	Q(5)	N.A.	N.A.	1, 2, 3(3)

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST #	MODES FOR WHICH SURVEILLANCE IS REQUIRED
4. Steamline Isolation (Continued)						
c. Containment Pressure--High-High Coincident with:	N.A.	R	N.A.	R	M(1)	1, 2, 3
Containment Pressure--High	N.A.	R	N.A	R	M(1)	1, 2, 3
d. Steam Line Flow--High Coincident with:	S(3)	R(a)(b)	Q(5)(a)(b)	N.A.	N.A.	1, 2, 3
Steam Generator Pressure--Low	S(3)	R(a)(b)	Q(5)(a)(b)	N.A.	N.A.	1, 2, 3
or						
Tavg--Low	S(3)	R	Q(5)	N.A.	N.A.	1, 2, 3
5. Feedwater Isolation						
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	R	1, 2, 3
b. Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.					
c. Steam Generator Water Level--High-High	S	R(a)(b)	Q(a)(b)	N.A.	N.A.	1, 2, 3
6. Auxiliary Feedwater (2)						
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	R	1, 2, 3
b. Steam Generator Water Level--Low-Low	S	R(a)(b)	Q(a)(b)	N.A.	N.A.	1, 2, 3

TABLE 4.3-2 (Continued)
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

CHANNEL FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST #	MODES FOR WHICH SURVEILLANCE IS REQUIRED
8. Engineering Safety Features Actuation System Interlocks						
a. Pressurizer Pressure	N.A.	R	Q(5)	N.A.	N.A.	1, 2, 3(3)
b. Tavg--Low	N.A.	R	Q(5)	N.A.	N.A.	1, 2, 3(3)
9. Control Room Ventilation Isolation						
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.	
b. Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.					
c. Containment Radioactivity--High	S	R	M	N.A.	N.A.	(4)
d. Containment Isolation Manual Phase A or Manual Phase B	N.A.	N.A.	N.A.	R	N.A.	1, 2, 3, 4
e. Control Room Air Intake Radiation Level	S	R	M	N.A.	N.A.	All

TABLE 4.3-2 (Continued)
ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION
SURVEILLANCE REQUIREMENTS

TABLE NOTATIONS

At least once per 18 months each Actuation Logic Test shall include energization of each relay and verification of OPERABILITY of each relay.

(a) If the as-found channel setpoint is outside its predefined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(b) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Nominal Trip Setpoint (NTS) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the NTS are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the surveillance procedures (field settings) to confirm channel performance. The NTS and methodologies used to determine the as-found and the as-left tolerances are specified in UFSAR Section 7.2

(1) Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(2) Auxiliary feedwater manual initiation is included in Specification 3.7.1.2.

(3) The provisions of Specification 4.0.4 are not applicable for entering Mode 3, provided that the applicable surveillances are completed within 96 hours from entering Mode 3.

(4) Applicable in MODES 1, 2, 3, 4 or during CORE ALTERATIONS or movement of irradiated fuel within the containment.

(5) Test of alarm function not required when alarm locked in.

TABLE 3.3-4 (Continued)
TABLE NOTATIONS

* During CORE ALTERATIONS or movement of irradiated fuel within the containment comply with Specification 3/4.9.13.

** With irradiated fuel in the spent fuel pits.

\# Unit 4 Spent Fuel Pool Area is monitored by Plant Vent radioactivity instrumentation.

Note 1 Either the particulate or gaseous channel in the OPERABLE status will satisfy this LCO.

Note 2 Containment Gaseous Monitor Setpoint = $\frac{(3.2 \times 10^4)}{(\quad F \quad)}$ CPM,

$$\text{Where } F = \frac{\text{Actual Purge Flow}}{\text{Design Purge Flow (35,000 CFM)}}$$

Setpoint may vary according to current plant conditions provided that the release rate does not exceed allowable limits provided in the Offsite Dose Calculation Manual.

ACTION STATEMENTS

ACTION 26 - In MODES 1 thru 4: With both the Particulate and Gaseous Radioactivity Monitoring Systems inoperable, operation may continue for up to 7 days provided:

1) A Containment sump level monitoring system is OPERABLE,

2) Appropriate grab samples are obtained and analyzed at least once per 24 hours,

3) A Reactor Coolant System water inventory balance is performed at least once per 8*** hours except when operating in shutdown cooling mode, and

4) Containment Purge, Exhaust and Instrument Air Bleed Valves are maintained closed.****

Otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours (ACTION 27 applies in MODES 5 and 6).

*** Not required to be performed until 12 hours after establishment of steady state operation.

**** Instrument Air Bleed Valves may be opened intermittently under administrative controls.

REACTOR COOLANT SYSTEM

3/4.4.2 SAFETY VALVES

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.2.1 A minimum of one pressurizer Code safety valve shall be OPERABLE* with a lift setting of 2465 psig + 2%, -3%.** ***

APPLICABILITY: MODES 4 and 5.

ACTION:

With no pressurizer Code safety valve OPERABLE, immediately suspend all operations involving positive reactivity changes and place an OPERABLE RHR loop into operation in the shutdown cooling mode.

SURVEILLANCE REQUIREMENTS

4.4.2.1 No additional requirements other than those required by Specification 4.0.5.

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* While in MODE 5, an equivalent size vent pathway may be used provided that the vent pathway is not isolated or sealed.

** The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

*** All valves tested must have "as left" lift setpoints that are within ± 1% of the lift setting value.

REACTOR COOLANT SYSTEM

OPERATING

LIMITING CONDITION FOR OPERATION

3.4.2.2 All pressurizer Code safety valves shall be OPERABLE with a lift setting of 2465 psig + 2%, -3%.* **

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

With one pressurizer Code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.2.2 No additional requirements other than those required by Specification 4.0.5.

* The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

** All valves tested must have "as left" lift setpoints that are within ± 1% of the lift setting value.

REACTOR COOLANT SYSTEM

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.6.1 The following Reactor Coolant System Leakage Detection Systems shall be OPERABLE:

a. The Containment Atmosphere Gaseous or Particulate Radioactivity Monitoring System, and

b. A Containment Sump Level Monitoring System.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With both the Particulate and Gaseous Radioactivity Monitoring Systems inoperable, operation may continue for up to 7 days provided:

1) A Containment Sump Level Monitoring System is OPERABLE;

2) Appropriate grab samples are obtained and analyzed at least once per 24 hours;

3) A Reactor Coolant System water inventory balance is performed at least once per 8* hours except when operating in shutdown cooling mode; and

4) Containment Purge, Exhaust and Instrument Air Bleed valves are maintained closed.**

Otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With no Containment Sump Level Monitoring System operable, restore at least one Containment Sump Level Monitoring System to OPERABLE status within 7 days, or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1 The Leakage Detection System shall be demonstrated OPERABLE by:

a. Containment Atmosphere Gaseous and Particulate Monitoring System-performance of CHANNEL CHECK, CHANNEL CALIBRATION and ANALOG CHANNEL OPERATIONAL TEST at the frequencies specified in Table 4.3-3, and

b. Containment Sump Level Monitoring System-performance of CHANNEL CALIBRATION at least once per 18 months.

* Not required to be performed until 12 hours after establishment of steady state operation.

** Instrument Air Bleed valves may be opened intermittently under administrative controls.

MATERIAL PROPERTY BASIS

LIMITING MATERIALS: Intermediate/Lower Shell Circumferential Weld Seams Ht. # 71249 and Upper Shell Forging

LIMITING ART VALUES AT 48 EFPY: 1/4 T, 231°F (Circ Flaw ART), 141°F (Axial Flaw ART)
3/4 T, 192°F (Circ Flaw ART), 124°F (Axial Flaw ART)

FPL/FLA 48 EFPY HEATUP CURVES

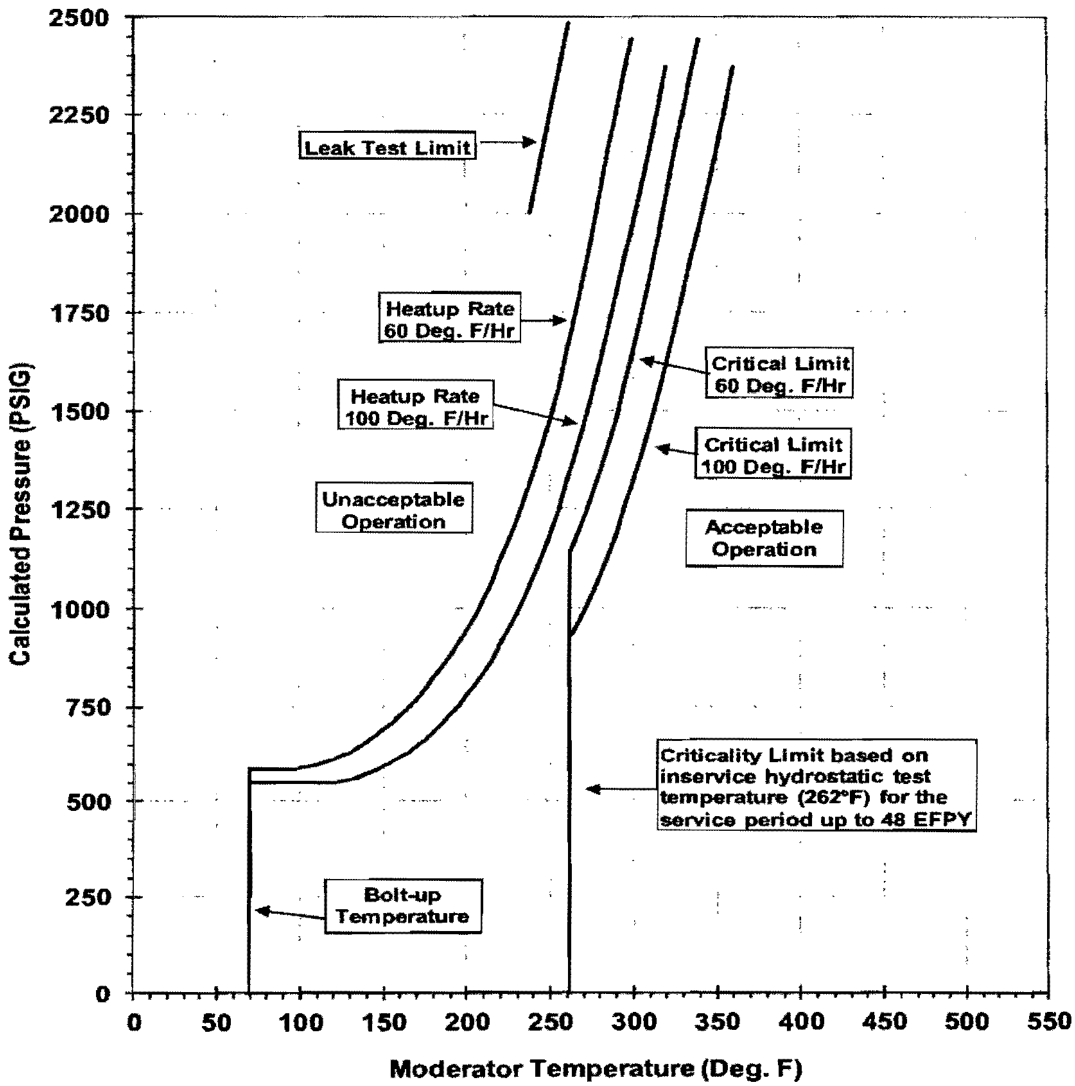

FIGURE 3.4-2 Turkey Point Units 3 and 4 Reactor Coolant System Heatup Limitations (Heatup Rates of 60 and 100°F/hr) Applicable for 48 EFPY (Without Margins for Instrumentation Errors)

MATERIAL PROPERTY BASIS

LIMITING MATERIALS: Intermediate/Lower Shell Circumferential Weld Seams Ht. # 71249 and Upper Shell Forging

LIMITING ART VALUES AT 48 EFPY: 1/4 T, 231°F (Circ Flaw ART), 141°F (Axial Flaw ART)
3/4 T, 192°F (Circ Flaw ART), 124°F (Axial Flaw ART)

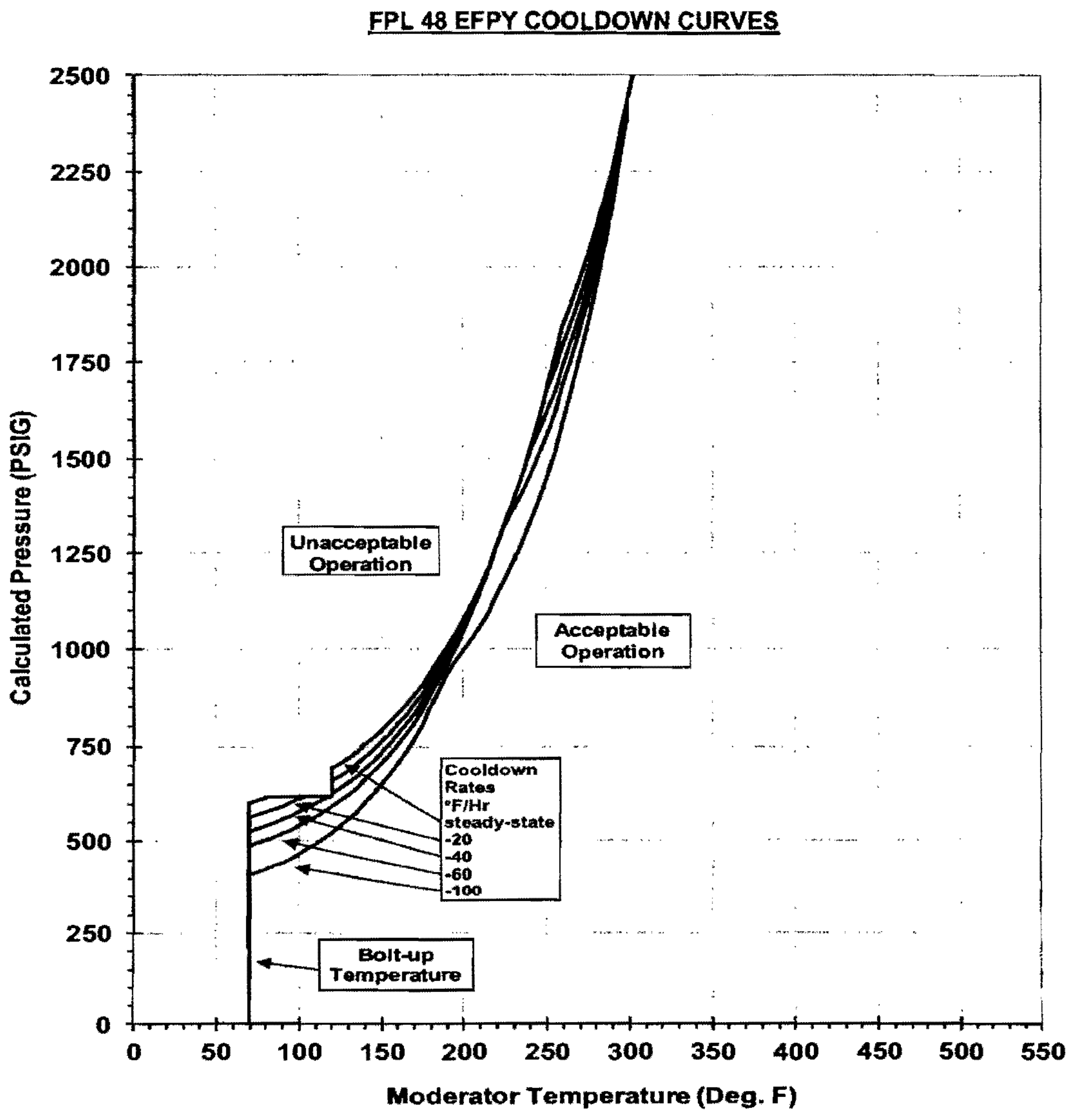

FIGURE 3.4-3 Turkey Point Units 3 and 4 Reactor Coolant System Cooldown Limitations (Cooldown Rates of 0, 20, 40, 60 and 100°F/hr) Applicable for 48 EFPY (Without Margins for Instrumentation Errors)

REACTOR COOLANT SYSTEM

OVERPRESSURE MITIGATING SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.9.3 The high pressure safety injection flow paths to the Reactor Coolant System (RCS) shall be isolated, and at least one of the following Overpressure Mitigating Systems shall be OPERABLE:

a. Two power-operated relief valves (PORVs) with a lift setting of ≤ 448 psig, or

b. The RCS depressurized with a RCS vent of greater than or equal to 2.20 square inches.

APPLICABILITY MODES 4 (when the temperature of any RCS cold leg is less than or equal to 275°F), 5, and 6 with the reactor vessel head on.

ACTION:

a. With the high pressure safety injection flow paths to the RCS unisolated, restore isolation of these flow paths within 4 hours.

b. With one PORV inoperable in MODE 4 (when the temperature of any RCS cold leg is less than or equal to 275°F), restore the inoperable PORV to OPERABLE status within 7 days or depressurize and vent the RCS through at least a 2.20 square inch vent within the next 8 hours.

c. With one PORV inoperable in Modes 5 or 6 with the reactor vessel head on, either (1) restore the inoperable PORV to OPERABLE status within 24 hours, or (2) complete depressurization and venting of the RCS through at least a 2.20 square inch vent within a total of 32 hours, or (3) complete depressurization and venting of the RCS through at least one open PORV and associated block valve within a total of 32 hours.

d. With both PORVs inoperable, either restore one PORV to OPERABLE status or complete depressurization and venting of the RCS through at least a 2.20 square inch vent within 24 hours.

e. In the event either the PORVs or a 2.20 square inch vent is used to mitigate an RCS pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the PORVs or RCS vent(s) on the transient, and any corrective action necessary to prevent recurrence. A Special Report is not required when such a transient is the result of water injection into the RCS for test purposes with an open vent path.

f. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 31 days and within 6 hours after each solution volume increase of greater than or equal to 1% of tank volume by verifying the boron concentration of the solution in the water-filled accumulator is between 2300 and 2600 ppm;

c. At least once per 31 days, when the RCS pressure is above 1000 psig, by verifying that the power to the isolation valve operator is disconnected by a locked open breaker.

d. At least once per 18 months, each accumulator check valve shall be checked for operability.

3/4.5.4 REFUELING WATER STORAGE TANK

LIMITING CONDITION FOR OPERATION

3.5.4 For single Unit operation, one refueling water storage tank (RWST) shall be OPERABLE or for dual Unit operation two RWSTs shall be OPERABLE with:

a. A minimum indicated borated water volume of 320,000 gallons per RWST,

b. A boron concentration between 2400 ppm and 2600 ppm,

c. A minimum solution temperature of 39°F, and

d. A maximum solution temperature of 100°F.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With less than the required number of RWST(s) OPERABLE, restore the tank(s) to OPERABLE status within 1 hour or be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.5.4 The required RWST(s) shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1) Verifying the indicated borated water volume in the tank, and

2) Verifying the boron concentration of the water.

b. By verifying the RWST temperature is within limits whenever the outside air temperature is less than 39°F or greater than 100°F at the following frequencies:

1) Within one hour upon the outside temperature exceeding its limit for consecutive 23 hours, and

2) At least once per 24 hours while the outside temperature exceeds its limit.

CONTAINMENT SYSTEMS

INTERNAL PRESSURE

LIMITING CONDITION FOR OPERATION

3.6.1.4 Primary containment internal pressure shall be maintained between -2 and +1 psig.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With the containment internal pressure outside of the limits above, restore the internal pressure to within the limits within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.4 The primary containment internal pressure shall be determined to be within the limits at least once per 12 hours.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER LEVEL WITH
INOPERABLE STEAM LINE SAFETY VALVES DURING THREE LOOP OPERATION

MAXIMUM NUMBER OF INOPERABLE SAFETY VALVES ON ANY OPERATING STEAM GENERATOR	MAXIMUM ALLOWABLE POWER LEVEL (PERCENT OF RATED THERMAL POWER)
1	44
2	27
3	10

TABLE 3.7-2

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER	Loop A	Loop B	Loop C	LIFT SETTING (±3%)* **	ORIFICE SIZE SQUARE INCHES
1.	RV1400	RV1405	RV1410	1085 psig	16
2.	RV1401	RV1406	RV1411	1100 psig	16
3.	RV1402	RV1407	RV1412	1105 psig	16
4.	RV1403	RV1408	RV1413	1105 psig	16

*The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

**All valves tested must have "as left" lift setpoints that are within ±1% of the lift setting value listed in Table 3.7-2.

PLANT SYSTEMS

STANDBY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.6 Two Standby Steam Generator Feedwater Pumps shall be OPERABLE* and at least 145,000 gallons of water (indicated volume), shall be in the Demineralized Water Storage Tank.**

APPLICABILITY: MODES 1, 2 and 3

ACTION:

a. With one Standby Steam Generator Feedwater Pump inoperable, restore the inoperable pump to available status within 30 days or submit a SPECIAL REPORT per 3.7.1.6d.

b. With both Standby Steam Generator Feedwater Pumps inoperable, restore at least one pump to OPERABLE status within 24 hours, or:

    1. Notify the NRC within the following 4 hours, and provide cause for the inoperability and plans to restore pump(s) to OPERABLE status and,

    2. Submit a SPECIAL REPORT per 3.7.1.6d.

c. With less than 145,000 gallons of water indicated in the Demineralized Water Storage Tank restore the available volume to at least 145,000 gallons indicated within 24 hours or submit a SPECIAL REPORT per 3.7.1.6d.

d. If a SPECIAL REPORT is required per the above specifications submit a report describing the cause of the inoperability, action taken and a schedule for restoration within 30 days in accordance with 6.9.2.

SURVEILLANCE REQUIREMENTS

4.7.1.6.1 The Demineralized Water Storage tank water volume shall be determined to be within limits at least once per 24 hours.

4.7.1.6.2 At least monthly verify the standby feedwater pumps are OPERABLE by testing in recirculation on a STAGGERED TEST BASIS.

4.7.1.6.3 At least once per 18 months, verify operability of the respective standby steam generator feedwater pump by starting each pump and providing feedwater to the steam generators.

*These pumps do not require plant safety related emergency power sources for operability and the flowpath is normally isolated.

**The Demineralized Water Storage Tank is non-safety grade.

PLANT SYSTEMS

3/4.7.1.7 FEEDWATER ISOLATION

LIMITING CONDITION FOR OPERATION

3.7.1.7 Six Feedwater Control Valves (FCVs) both main and bypass and six Feedwater Isolation Valves (FIVs) both main and bypass shall be OPERABLE.*

APPLICABILITY: MODES 1, 2 and 3**

ACTION:

a. With one or more FCVs inoperable, restore operability, or close or isolate the inoperable FCVs within 72 hours and verify that the inoperable valve(s) is closed or isolated at least once per 7 days or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With one or more FIVs inoperable, restore operability, or close or isolate the inoperable FIV(s) within 72 hours and verify that the inoperable valve(s) is closed or isolated at least once per 7 days or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With one or more bypass valves in different steam generator flow paths inoperable, restore operability, or close or isolate the inoperable bypass valve(s) within 72 hours and verify that the inoperable valve(s) is closed or isolated at least once per 7 days or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

d. With two valves in the same steam generator flow path inoperable, restore operability, or isolate the affected flowpath within 8 hours or be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.7 Each FCV, FIV and bypass valve shall be demonstrated OPERABLE:

a. At least every 18 months by:

    1) Verifying that each FCV, FIV and bypass valve actuates to the isolation position on an actual or simulated actuation signal.

b. In accordance with the Inservice Testing Program by:

    1) Verifying that each FCV, FIV and bypass valve isolation time is within limits.

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*Separate Condition entry is allowed for each valve.

**The provisions of specification 3.0.4 and 4.0.4 are not applicable.

4.8.1.1.2 Each diesel generator shall be demonstrated OPERABLE*:

a. At least once per 31 days on a STAGGERED TEST BASIS by:

1) Verifying the fuel volume in the day and skid-mounted fuel tanks (Unit 4-day tank only),

2) Verifying the fuel volume in the fuel storage tank,

3) Verifying the lubricating oil inventory in storage,

4) Verifying the diesel starts and accelerates to reach a generator voltage and frequency of 3950-4350 volts and 60 ± 0.6 Hz. Once per 184 days, these conditions shall be reached within 15 seconds after the start signal from normal conditions. For all other starts, warmup procedures, such as idling and gradual acceleration as recommended by the manufacturer may be used. The diesel generator shall be started for this test by using one of the following signals:

a) Manual, or

b) Simulated loss-of-offsite power by itself, or

c) Simulated loss-of-offsite power in conjunction with an ESF Actuation test signal, or

d) An ESF Actuation test signal by itself.

5) Verifying the generator is synchronized, loaded** to 2300 - 2500 kW (Unit 3), 2650-2850 kW (Unit 4)***, operates at this loaded condition for at least 60 minutes and for Unit 3 until automatic transfer of fuel from the day tank to the skid mounted tank is demonstrated, and the cooling system is demonstrated OPERABLE.

6) Verifying the diesel generator is aligned to provide standby power to the associated emergency busses.

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* All diesel generator starts for the purpose of these surveillances may be proceeded by a prelube period as recommended by the manufacturer.

** May include gradual loading as recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized.

***Momentary transients outside these load bands do not invalidate this test.

SURVEILLANCE REQUIREMENTS (Continued)

b. Demonstrating at least once per 92 days that a fuel transfer pump starts automatically and transfers fuel from the storage system to the day tank,

c. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by checking for and removing accumulated water from the day and skid-mounted fuel tanks (Unit 4-day tank only);

d. At least once per 31 days by checking for and removing accumulated water from the fuel oil storage tanks;

e. By verifying fuel oil properties of new fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.

f. By verifying fuel oil properties of stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.

g. At least once per 18 months, during shutdown (applicable to only the two diesel generators associated with the unit):

1) Deleted

2)* Verifying the generator capability to reject a load of greater than or equal to 380 kw while maintaining voltage at 3950-4350 volts and frequency at 60 ± 0.6 Hz;

3)* Verifying the generator capability to reject a load of greater than or equal to 2500 kW (Unit 3), 2874 kW (Unit 4) without tripping. The generator voltage shall return to less than or equal to 4784 volts within 2 seconds following the load rejection;

4) Simulating a loss-of-offsite power by itself, and:

a) Verifying deenergization of the emergency busses and load shedding from the emergency busses, and

b. Verifying the diesel starts on the auto-start signal, energizes the emergency busses with any permanently

* For the purpose of this test, warmup procedures, such as idling, gradual acceleration, and gradual loading as recommended by the manufacturer may be used.

connected loads within 15 seconds, energizes the auto–connected shutdown loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the auto-connected shutdown loads. After automatic load sequencing, the steady-state voltage and frequency of the emergency busses shall be maintained at 3950-4350 volts and 60 ± 0.6 Hz during this test.

5) Verifying that on an ESF Actuation test signal, without loss-of-offsite power, the diesel generator starts on the auto-start signal and operates on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 3950-4350 volts and 60 ± 0.6 Hz within 15 seconds after the auto-start signal; the steady-state generator voltage and frequency shall be maintained within these limits during this test;

6) Simulating a loss-of-offsite power in conjunction with an ESF Actuation test signal, and:

a) Verifying deenergization of the emergency busses and load shedding from the emergency busses;

b) Verifying the diesel starts on the auto-start signal, energizes the emergency busses with any permanently connected loads within 15 seconds, energizes the auto-connected emergency (accident) loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After automatic load sequencing, the steady-state voltage and frequency of the emergency busses shall be maintained at 3950-4350 volts and 60 ± 0.6 Hz during this test; and

c) Verifying that diesel generator trips that are made operable during the test mode of diesel operation are inoperable.

7)* # Verifying the diesel generator operates for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to 2550-2750 kW (Unit 3), 2950-3150 kW (Unit 4)** and during the remaining 22 hours of this test, the diesel generator shall be loaded to 2300-2500 kW (Unit 3), 2650-2850 kW (Unit 4)**. The generator voltage and frequency shall be 3950-4350 volts and 60 ± 0.6 Hz within 15 seconds after the start signal; the steady-state generator voltage and frequency

* For the purpose of this test, warmup procedures, such as idling, gradual acceleration, and gradual loading as recommended by the manufacturer may be used.

** Momentary transients outside these load bands do not invalidate this test.

This test may be performed during POWER OPERATION

shall be maintained within these limits during this test. Within 5 minutes after completing this 24-hour test, verify the diesel starts and accelerates to reach a generator voltage and frequency of 3950-4350 volts and 60 ± 0.6 Hz within 15 seconds after the start signal.**

8) Verifying that the auto-connected loads to each diesel generator do not exceed 2500 kW (Unit 3), 2874 kW (Unit 4);

9) Verifying the diesel generator's capability to:

   a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

   b) Transfer its loads to the offsite power source, and

   c) Be restored to its standby status.

10) Verifying that the diesel generator operating in a test mode, connected to its bus, a simulated Safety Injection signal overrides the test mode by: (1) returning the diesel generator to standby operation, and (2) automatically energizing the emergency loads with offsite power;

11) Verifying that the fuel transfer pump transfers fuel from the fuel storage tank (Unit 3), fuel storage tanks (Unit 4) to the day tanks of each diesel associated with the unit via the installed cross-connection lines;

12) Verifying that the automatic load sequence timer is OPERABLE with the interval between each load block within ± 10% of its design interval;

13) Verifying that the diesel generator lockout relay prevents the diesel generator from starting;

** If verification of the diesel's ability to restart and accelerate to a generator voltage and frequency of 3950-4350 volts and 60 ± 0.6 Hz within 15 seconds following the 24 hour operation test of Specification 4.8.1.1.2.g.7) is not satisfactorily completed, it is not necessary to repeat the 24-hour test. Instead, the diesel generator may be operated between 2300-2500 kW Unit 3, 2650-2850 kW (Unit 4) for 2 hours or until operating temperature has stabilized (whichever is greater). Following the 2 hours/operating temperature stabilization run, the EDG is to be secured and restarted within 5 minutes to confirm its ability to achieve the required voltage and frequency within 15 seconds.

h. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all required diesel generators simultaneously and verifying that all required diesel generators provide 60 ± 0.6 Hz frequency and 3950-4350 volts in less than or equal to 15 seconds: and

I. At least once per 10 years by:

1) Draining each fuel oil storage tank, removing the accumulated sediment and cleaning the tank.*

2) For Unit 4 only, performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda.

4.8.1.1.3 Reports - (Not Used)

* A temporary Class III fuel storage system containing a minimum volume of 38,000 gallons of fuel oil may be used for up to 10 days during the performance of Surveillance Requirement 4.8.1.1.2i.1 for the Unit 3 storage tank while Unit 3 is in Modes 5. 6. or defueled. If the diesel fuel oil storage tank is not returned to service within 10 days. Technical Specification 3.8.1.1 Action b and 3.8.1.2 Action apply to Unit 4 and Unit 3 respectively.

3/4.9 REFUELING OPERATIONS

3/4.9.1 BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.9.1 The boron concentration of all filled portions of the Reactor Coolant System and the refueling canal shall be maintained uniform and sufficient to ensure that the more restrictive of the following reactivity conditions is met; either:

a. A K_{eff} of 0.95 or less, or

b. A boron concentration of greater than or equal to 2300 ppm.

APPLICABILITY: MODE 6.*

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at greater than or equal to 16 gpm of a solution containing greater than or equal to 3.0 wt% (5245 ppm) boron or its equivalent until K_{eff} is reduced to less than or equal to 0.95 or the boron concentration is restored to greater than or equal to 2300 ppm, whichever is the more restrictive.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The more restrictive of the above two reactivity conditions shall be determined prior to:

a. Removing or unbolting the reactor vessel head, and

b. Withdrawal of any full-length control rod in excess of 3 feet from its fully inserted position within the reactor vessel.

4.9.1.2 The boron concentration of the Reactor Coolant System and the refueling canal shall be determined by chemical analysis at least once per 72 hours.

4.9.1.3 Valves isolating unborated water sources** shall be verified closed and secured in position by mechanical stops or by removal of air or electrical power at least once per 31 days.

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* The reactor shall be maintained in MODE 6 whenever fuel is in the reactor vessel with the vessel head closure bolts less than fully tensioned or with the head removed.

** The primary water supply to the boric acid blender may be opened under administrative controls for makeup.

3/4.9.14 SPENT FUEL STORAGE

LIMITING CONDITION FOR OPERATION

3.9.14 The following conditions shall apply to spent fuel storage:

a. The minimum boron concentration in the Spent Fuel Pit shall be 2300 ppm.

b. The combination of initial enrichment, burnup, and cooling time of each fuel assembly stored in the Spent Fuel Pit shall be in accordance with Specification 5.5.1.

APPLICABILITY: At all times when fuel is stored in the Spent Fuel Pit.

ACTION:

a. With boron concentration in the Spent Fuel Pit less than 2300 ppm, suspend movement of spent fuel in the Spent Fuel Pit and initiate action to restore boron concentration to 2300 ppm or greater.

b. With condition b not satisfied, suspend movement of additional fuel assemblies into the Spent Fuel Pit and restore the spent fuel storage configuration to within the specified conditions.

c. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.14.1 The boron concentration of the Spent Fuel Pit shall be verified to be 2300 ppm or greater at least once per month.

4.9.14.2 A representative sample of inservice Metamic inserts shall be visually inspected in accordance with the Metamic Surveillance Program described in UFSAR Section 16.2. The surveillance program ensures that the performance requirements of Metamic are met over the surveillance interval.

5.5 FUEL STORAGE

5.5.1 CRITICALITY

5.5.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. A k_{eff} less than 1.0 when flooded with unborated water, which includes an allowance for biases and uncertainties as described in UFSAR Chapter 9.

b. A k_{eff} less than or equal to 0.95 when flooded with water borated to 500 ppm, which includes an allowance for biases and uncertainties as described in UFSAR Chapter 9.

c. A nominal 10.6 inch center-to-center distance for Region I and 9.0 inch center-to-center distance for Region II for the two region spent fuel pool storage racks. A nominal 10.1 inch center-to-center distance in the east-west direction and a nominal 10.7 inch center-to-center distance in the north-south direction for the cask area storage rack.

d. A maximum enrichment loading for fuel assemblies of 5.0 weight percent of U-235.

e. No restriction on storage of fresh or irradiated fuel assemblies in the cask area storage rack.

f. Fresh or irradiated fuel assemblies not stored in the cask area storage rack shall be stored in accordance with Specification 5.5.1.3.

g. The Metamic neutron absorber inserts shall have a minimum certified ^{10}B areal density greater than or equal to 0.015 grams $^{10}B/cm^2$.

5.5.1.2 The racks for new fuel storage are designed to store fuel in a safe subcritical array and shall be maintained with:

a. A nominal 21 inch center-to-center spacing to assure k_{eff} equal to or less than 0.98 for optimum moderation conditions and equal to or less than 0.95 for fully flooded conditions.

b. Fuel assemblies placed in the New Fuel Storage Area shall contain no more than a nominal 4.5 weight percent of U-235 if the assembly contains no burnable absorber rods and no more than 5.0 weight percent of U-235 if the assembly contains at least 16 IFBA rods.

5.6 COMPONENT CYCLIC OR TRANSIENT LIMIT

5.6.1 The components identified in Table 5.6-1 are designed and shall be maintained within the cyclic or transient limits of Table 5.6-1.

TABLE 5.6-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor Coolant System	200 heatup cycles at $\leq$ 100°F/h and 200 cooldown cycles at $\leq$ 100°F/h.	Heatup cycle - T_{avg} from $\leq$ 200°F to $\geq$ 550°F. Cooldown cycle - T_{avg} from $\geq$ 550°F to $\leq$ 200°F.
	200 pressurizer cooldown cycles at $\leq$ 200°F/h from nominal pressure.	Pressurizer cooldown cycle temperatures from $\geq$ 650°F to $\leq$ 200°F.
	200 pressurizer cooldown cycles $\leq$ 200°F/h from 400 psia.	Pressurizer cooldown cycle temperatures from $\geq$ 650°F to $\leq$ 200°F.
	80 loss of load cycles, without immediate Turbine or Reactor trip.	$\geq$ 15% of RATED THERMAL POWER to 0% of RATED THERMAL POWER.
	40 cycles of loss-of-offsite A.C. electrical power.	Loss-of-offsite A.C. electrical ESF Electrical System.
	80 cycles of loss of flow in one reactor coolant loop.	Loss of only one reactor coolant pump.
	400 Reactor trip cycles.	100% to 0% of RATED THERMAL POWER.
	10 cycles of inadvertent auxiliary spray	Spray water temperature differential to 560°F.
	150 primary to secondary side leak tests.	Pressurized to 2435 psig.
	15 primary to secondary side leak tests.	Pressurized to 2250 psig.
	5 hydrostatic pressure tests.	Pressurized to 2485 psig and 400°F.
Secondary Coolant System		
	50 hydrostatic pressure tests	Pressurized to 1085 psig
	10 hydrostatic pressure tests.	Pressurized to 1356 psig.
	15 secondary to primary side leak tests	Pressurized to 840 psig

9. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half lives greater than 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

10. Limitations on the annual dose or dose commitment to any member of the public, beyond the site boundary, due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

The provisions of Specifications 4.0.2 and 4.0.3 are applicable to the Radioactive Effluent Controls Program surveillance frequency.

g. Deleted

h. Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, and as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by the following deviations or exemptions:

1) Type A tests will be performed either in accordance with Bechtel Topical Report BN-TOP-1, Revision 1, dated November 1, 1972, or the guidelines of Regulatory Guide 1.163.

2) Type A testing frequency in accordance with NEI 94-01, Revision 0, Section 9.2.3, except:

   a) For Unit 3, the first Type A test performed after the November 1992 Type A test shall be performed no later than November 2007.

   b) For Unit 4, the first Type A test performed after October 1991 shall be performed no later than October 2006.

3) A vacuum test will be performed in lieu of a pressure test for airlock door seals at the required intervals (Amendment Nos. 73 and 77, issued by NRC November 11, 1981).

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is defined here as the containment design pressure of 55 psig.

The maximum allowable containment leakage rate, L_a, at P_a, shall be 0.20% of containment air weight per day.

Leakage Rate acceptance criteria are:

1) The As-found containment leakage rate acceptance criterion is $\leq$ 1.0 L_a. Prior to increasing primary coolant temperature above 200°F following testing in accordance with this program or restoration from exceeding 1.0 L_a, the As-left leakage rate acceptance criterion is $\leq$0.75 L_a, for Type A test.

2) The combined leakage rate for all penetrations subject to Type B or Type C testing is as follows:

3. WCAP-10054-P-A, Addendum 2, Revision 1 (proprietary), "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," July 1997.

4. WCAP-16009-P-A, "Realistic Large-break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)", January 2005.

5. USNRC Safety Evaluation Report, Letter from R. C. Jones (USNRC) to N. J. Liparulo (W), "Acceptance for Referencing of the Topical Report WCAP-12945(P) 'Westinghouse Code Qualification Document for Best Estimate Loss of Coolant Analysis,' " June 28, 1996.**

6. Letter dated June 13, 1996, from N. J. Liparulo (W) to Frank R. Orr (USNRC), "Re-Analysis Work Plans Using Final Best Estimate Methodology."**

7. WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report," S. L. Davidson and T. L. Ryan, April 1995.

The analytical methods used to determine Overtemperature ΔT and Overpower ΔT shall be those previously reviewed and approved by the NRC in:

1. WCAP-8745-P-A, " Design Basis for the Thermal Overtemperature ΔT and Overpower ΔT Trip Functions, " September 1986

2. WCAP-9272-P-A, " Westinghouse Reload Safety Evaluation Methodology," July 1985

The analytical methods used to determine Safety Limits, Shutdown Margin - $T_{avg} > 200°F$, Shutdown Margin - $T_{avg} \leq 200°F$, Moderator Temperature Coefficient, DNB Parameters, Rod Bank Insertion Limits and the All Rods Out position shall be those previously reviewed and approved by the NRC in:

1. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

The ability to calculate the COLR nuclear design parameters are demonstrated in:

1. Florida Power & Light Company Topical Report NF-TR-95-01, "Nuclear Physics Methodology for Reload Design of Turkey Point & St. Lucie Nuclear Plants."

Topical Report NF-TR-95-01 was approved by the NRC for use by Florida Power & Light Company in:

1. Safety Evaluation by the Office of Nuclear Reactor Regulations Related to Amendment No. 174 to Facility Operating License DPR-31 and Amendment No. 168 to Facility Operating License DPR-41, Florida Power & Light Company Turkey Point Units 3 and 4, Docket Nos. 50-250 and 50-251.

The AFD, $F_Q(Z)$, $F_{\Delta}H$, K(Z), Safety Limits, Overtemperature ΔT, Overpower ΔT, Shutdown Margin - $T_{avg} > 200°F$, Shutdown Margin -$T_{avg} \leq 200°F$, Moderator Temperature Coefficient, DNB Parameters, and Rod Bank Insertion Limits shall be determined such that all applicable limits of the safety analyses are met. The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector, unless otherwise approved by the Commission.

**As evaluated in NRC Safety Evaluation dated December 20, 1997.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO.249 TO

RENEWED FACILITY OPERATING LICENSE NO. DPR-31 AND

AMENDMENT NO. 245 TO RENEWED FACILITY OPERATING LICENSE NO. DPR-41

FLORIDA POWER AND LIGHT COMPANY

TURKEY POINT PLANT, UNIT NOS. 3 AND 4

DOCKET NOS. 50-250 AND 50-251

Proprietary information pursuant to
Title 10 of the *Code of Federal Regulations* Section 2.390
has been redacted from this document.
Redacted information is identified by blank space enclosed within double brackets

TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 Application

By letters dated October 21, and December 14, 2010,[1] as supplemented by additional letters,[2] Florida Power & Light Company (FPL, the licensee), submitted an application to the U.S. Nuclear Regulatory Commission (NRC) for a license amendment regarding the extended power uprate (EPU) for Turkey Point Nuclear Plant (PTN) Units 3 and 4. The proposed amendment would increase the authorized maximum core power level of each unit from the current licensed thermal power of 2300 megawatts thermal (MWt) to 2644 MWt. This represents a net increase in licensed core thermal power of approximately 15 percent including a 13 percent power uprate and a 1.7 percent measurement uncertainty recapture.

1.2 Background

The PTN Units 3 and 4 are pressurized-water reactors of the Westinghouse three-loop design each with a vertical, cylindrical steel-lined, reinforced concrete containment. The NRC issued full-power operating licenses to PTN Units 3 and 4 on July 19, 1972, and April 10, 1973, respectively. Commercial operation commenced for Units 3 and 4 on December 1972 and September 1973, respectively. The units were licensed for a rated core thermal power output of 2200 MWt. In September 1996, a stretch power uprate (SPU) of approximately 4.5 percent was approved,[3] increasing each unit's rated thermal power to the current 2300 MWt. The SPU was based on the detailed evaluation of the nuclear steam supply system (including loss-of-coolant accident (LOCA), non-LOCA, containment responses and dose consequences), engineered

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[1] Agencywide Documents Access and Management System (ADAMS) Accession Number ML103560167.

[2] December 21, 2010 (ML103610319), January 7, 2011 (ML110120234), January 28, 2011 (ML110330189), February 22, 2011 (ML110560249), March 3, 2011 (ML110680074), March 9, 2011 (two letters - ML110700068 and ML110700066), March 16, 2011 (two letters - ML110770020 and ML110770019), March 23, 2011 (ML110840042), March 25, 2011 (ML110880060), March 31, 2011 (two letters - ML110940179 and ML110940040), April 14, 2011 (two letters - ML11105A146 and ML11105A145), April 22, 2011 (two letters - ML11115A114 and ML11115A113), April 26, 2011 (ML11118A025), April 28, 2011 (two letters - ML11119A134 and ML11119A135), April 29, 2011 (ML11124A107), May 11, 2011 (ML11137A080), May 18, 2011 (ML111390661), May 19, 2011 (two letters - ML111430246 and ML111430022), May 26, 2011 (two letters - ML11151A203 and ML11151A204), June 7, 2011 (ML11160A097), June 9, 2011 (ML11161A145), June 21, 2011 (two letters - ML11174A043 and ML111740856), July 7, 2011 (two letters - ML11192A204 and ML111920413), July 22, 2011 (ML11207A456), July 29, 2011 (ML112140344), August 5, 2011 (ML112210450), August 11, 2011 (ML11228A012), August 16, 2011 (two letters - ML11231A247 and ML11231A248), August 19, 2011 (ML11234A178), August 25, 2011 (two letters - ML11241A172 and ML11241A170), August 29, 2011 (ML11242A159), September 14, 2011 (ML11259A006), September 16, 2011 (ML11263A003), September 30, 2011 (two letters - ML11276A079 and ML11276A080), October 6, 2011 (ML112800564), October 12, 2011 (two letters - ML112901197 and ML11290A202), October 14, 2011 (ML11292A033), October 15, 2011 (ML11292A032), November 9, 2011 (ML11318A284), December 22, 2011 (two letters – ML11362A381 and ML113620406, December 31, 2011 (ML12009A113), January 10, 2012 (ML12011A187), January 16, 2012 (two letters - ML120200161 and ML120190026), January 17, 2012 (ML12018A393), January 19, 2012 (ML12023A032), January 23, 2012 (two letters - ML12025A080 and ML12025A081), January 25, 2012 (ML12027A011), January 31, 2012 (ML120330397), February 3, 2012 (ML12038A007), February 15, 2012 (ML12048A068), February 23, 2012 (two letters – ML120580184 and ML12058A126), and March 15, 2012 (ML120790306)

[3] ML013390234

safety features, power conversion, emergency power, support systems and environmental issues. On April 2002, as supplemented in May 2002,[4] NRC approved the license renewal for Units 3 and 4 through July 2032 and April 2033, respectively. The renewed operating licenses were issued in June 2002.

PTN Units 3 and 4 are located adjacent to oil- and gas-fired Units 1 and 2 and the gas-fired combined cycle Unit 5 at the Turkey Point Plant on the shore of Biscayne Bay, about 25 miles south of Miami, Florida. In June 2009, FPL submitted an application for a combined construction permit and operating license for two Westinghouse Advanced Passive 1000 pressurized-water reactors designated as PTN, Units 6 and 7.

1.3 Licensee's Approach

The licensee's application for the proposed EPU follows the guidance in the NRC's review standard, RS-001, "Review Standard for Extended Power Uprates," (December 2003) and regulatory issue summary, RIS 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Uprate Applications," (January 2002), to the extent that RS-001 and RIS 2002-03 are consistent with the design basis of the plant. The guidance of RS-001 states that EPUs are characterized by power level increases of 7 percent or more and generally involve major plant modifications.

1.4 Plant Modifications

The licensee described the following as the principal design changes and modifications associated with the EPU:

Fuel/Reactor Core Design

The PTN fuel design is expected to be transitioned from the current 15x15 seven-grid debris resistant fuel assembly design to the 15x15 seven-grid upgrade fuel assembly design one cycle prior to the EPU. PTN Units 3 and 4 are currently licensed to use fuel that has a maximum enrichment of 4.5 percent by weight uranium-235. The proposed amendment would increase that limit to 5 percent. The rod average discharge exposure would still not exceed 62,000 megawatt-days/metric ton uranium. The proposed license amendment request would change the Technical Specifications to allow both operation and storage of new and spent fuel at the higher enrichment level. Core operating limits will continue to be established using NRC-approved methodologies and all fuel design constraints will continue to be satisfied.

The Overpower ΔT and Overtemperature ΔT reactor trip will be adjusted for EPU conditions and the steam generator water level low and steam generator water level low-low trip setpoints will be revised from 10 percent narrow range to 16 percent. In addition, the installation of a 50/5 lead/lag on the low steamline pressure isolation signal will improve the results of the limiting main steamline break.

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[4] Reference NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 & 4" (ML021280496 and ML021560094, Supplement 1)

Reactor Coolant System

There are no physical modifications involving the addition of new equipment or replacement of existing equipment in the plant planned for the reactor coolant system (RCS) or reactor internals. The reactor coolant thermal design flow will increase approximately 2.2 percent reflecting a slight reduction in the flow resistance of the new fuel assemblies while also crediting the additional flow margin currently available. The system operating pressure will remain the same. The RCS operating temperatures, however, will change for the uprate. The design reactor vessel inlet temperature (T_{cold}) at 2644 MWt core power at the highest average temperature (T_{avg}) condition will be increased from 546.6 degrees Fahrenheit (°F) to 549.2 °F. The coolant temperature rise across the core will increase in proportion to the increase in power level. With the higher reactor vessel inlet temperature and increased temperature rise, the design vessel outlet temperature (T_{hot}) will increase from 607.8 °F to 616.8 °F, based on the RCS thermal design flow. The RCS no-load temperature will remain at the current value of 547 °F. Changes will be made to the pressurizer level control program to accommodate the higher RCS average temperature. In addition, as part of the safety analyses at EPU conditions, the pressurizer backup heater actuation on pressurizer high level deviation signal will be removed to improve the plant response to the loss of normal feedwater and loss of normal alternating current events. The current alarm on high pressurizer level deviation will be retained.

Emergency Core Cooling System

Due to increased core thermal power, the safety injection system will require a minimum of two high head safety injection pumps to maintain peak clad temperatures below their acceptance criteria. The residual heat removal system will continue to use a minimum of one low head safety injection pump in response to LOCA events. The post-LOCA subcriticality and long-term cooling analysis under EPU conditions has resulted in a revision to the allowable boron concentration in the accumulators from between 1950 and 2350 parts per million (ppm) to a range of 2300 to 2600 ppm. For the refueling water storage tank (RWST), the analysis has increased the minimum allowable boron concentration from 1950 ppm to 2400 ppm. The analysis also confirmed an acceptable maximum boron concentration requirement of 2600 ppm in the RWST to ensure that boric acid precipitation in the core is precluded.

Steam Generator and Main Steam

Both units are equipped with Model 44F steam generators. The original lower assemblies (i.e., tube sheets, etc.) were replaced for Units 3 and 4 in 1982 and 1983, respectively. As a result of the increased flow under EPU conditions, the main steam isolation valves (MSIVs) and main steam check valves (MSCVs) and associated supports will be upgraded to ensure their ability to withstand a steamline break, inadvertent closures and resist erosion. The best estimate steam generator outlet steam pressure for the uprate will decrease slightly due to the higher power level combined with a small increase in T_{avg}.

For the MSSVs to perform satisfactorily during their design basis loss of load with turbine trip at EPU conditions, the pressure setpoints of the two highest set safety valves will be reduced and the number required to be operable for a given power level will be changed.

Main Turbine

The Units 3 and 4 high pressure turbines will be replaced in order to pass the additional volumetric steam flow. New turbine digital controls, high lift control valves, electro-hydraulic control systems, and moisture separator reheaters will be implemented for the uprate. In addition, the gland steam system will be modified for uprate conditions. The low pressure turbines will not be modified as they are capable of passing the higher volumetric flow rate.

Main Condenser/Circulating Water/Cooling Canal

In order to ensure reliable operations at EPU conditions, the main condenser tube bundles, waterboxes, support plates, cathodic protection, and tube cleaning system will be replaced. The evaluation has shown that the existing Intake cooling water system flow rates are sufficient to provide the required plant cooling at EPU conditions. Modifications are being made to the nonsafety-related turbine plant cooling water heat exchangers to increase their heat capacity but the flow requirements are not increasing.

Condensate and Feedwater

The condensate and feedwater flow rates will increase in proportion to the uprate power increase. The condensate pumps and the feedwater pump rotating assemblies will be replaced to provide the operating characteristics necessary to meet the EPU hydraulic requirements for pump capacity and head. For EPU operation, feedwater isolation will continue to be provided by the feedwater control valves (FCVs). Although EPU is not changing their function, the existing FCVs are being modified to provide increased flow capacity for EPU conditions. Currently, the backup automatic feedwater isolation valve function is provided by the feedwater pump discharge motor operated valves. New fast acting feedwater isolation valves will be added just upstream of the current feedwater main and bypass flow control valves to perform the backup automatic feedwater isolation function. These modifications will reduce the severity of steamline break accidents under EPU conditions by reducing the feedwater mass added to containment through the break. The 5th and 6th feedwater heaters are being replaced with flow-accelerated corrosion resistant material. The replacement of the 6^{th} feedwater heaters results in the resizing and rerouting of the discharge piping, which in turn, requires modifications to shield equipment important to safety from enlarged jet impingement zones.

Auxiliary Feedwater

In order to assure that each of the three turbine-driven auxiliary feedwater pumps will be capable of achieving the increased minimum flow requirements for a loss of external load at EPU conditions, they will be refurbished and modified as necessary to meet performance requirements. The travel stops on the flow control valves will also be removed allowing them to fully open and minimize the flow resistance to the steam generators.

Spent Fuel Pool

In order to assure that current design limits are maintained at EPU conditions, a supplemental heat exchanger will be added to the cooling loop for each Unit. The modified cooling system will be designed to provide a minimum increase of 30 percent in cooling capacity relative to the

current system capability. The spent fuel pit pump motors will also be powered independently through separate breakers instead of from the same source through a transfer switch, thereby allowing simultaneous or independent operation for maintenance and operational flexibility.

Main Generator

The main generator electrical output of each unit will increase by approximately 130 megawatt electric. Each main generator will be rerated from 894 megavolt amperes (MVA) to 1032 MVA with an allowable power factor of 0.85. To support unit operation at EPU conditions, the required modifications include rewinding the stator, a new replacement rotor, and new current transformers. In addition, more efficient hydrogen coolers and exciter air coolers will be installed.

Emergency Diesel Generator

There are minor load additions as a result of the EPU including a loading increase at the extreme limits of emergency diesel generator (EDG) frequency and voltage. This would increase worst case EDG loading. In order to ensure that the EDGs remain within their ratings at these conditions, with margin, the voltage and frequency operation tolerances will be reduced.

Grid Stability

A system impact study consisting of a generation interconnection service and a network resource interconnection service was completed to evaluate the impact of the increased power output to the FPL transmission system. Thermal, voltage, stability as well as circuit breaker fault duty results, with and without PTN at EPU, were compared to determine any detrimental impact of the proposed EPU. The reactive capability analysis concluded that the units' increased turbine-generator capability meets the reactive capability requirements under EPU conditions and the short circuit analysis concluded that the fault current levels did not exceed the rating of any circuit breakers. However, in view of the uncertainty in the accuracy of modeling data, two new 5-ohm inductors, each with 90 nanofarads capacitors, will be installed on the southeast and southwest buses in the switchyard to reduce the available fault current. Power system stabilizers will be installed to improve oscillations damping.

Switchyard

The Unit 3 and 4 circuit breakers and disconnect switches proved to be acceptable under EPU conditions except for the four disconnect switches associated with the main transformer tie lines. These are undersized for EPU operation and will be replaced with switches that have 3000 amperes ratings. The other disconnect switches in Bays 7 and 9 associated with the 240 kilovolt buses and transmission line circuit breakers will also be uprated to 3000 amperes ratings. The multi-ratio current transformers in all the circuit breakers in Bays 7 and 9 will be adjusted to accommodate the increased unit output.

Risk Evaluation

There are several EPU modifications that have not been credited in the EPU probabilistic risk assessment that are expected to have an incremental benefit by reducing the likelihood of reactor and turbine trips, and increasing the resistance to loss-of-offsite power events. These include:

- A limited number of reactor protection setpoint changes to accommodate changes in plant operation brought about by EPU and installation of pressurizer pressure digital readouts to enhance readability.

- Removal of automatic actuation of backup pressurizer heaters on high pressurizer level deviation to improve plant response following loss of normal feedwater and loss of normal alternating current events.

- A number of upgrades to the switchyard and main generator to improve operational margin, ensure adequate cooling, and improve response to grid disturbances.

- Installation of digital electro-hydraulic controllers and a turbine digital control system and an upgrade of the high-pressure turbine rotor and blade technology to improve turbine performance and protection.

- Improvements in automatic turbine runback capability for anticipated transients to reduce reliance on operator actions.

- Installation of digital controllers in the feedwater heater drain system to increase system stability and reduce plant challenges associated with loss of normal feedwater events.

- An upgrade of the condensate pumps to accommodate increased flow requirements and improve operational margin.

The licensee's EPU Licensing Report (LR) Table 1.0-1, "PTN Unit 3 and Unit 4 Power Uprate Key Planned Modifications," summarizes the planned major modifications, as described below:

Modification	Category (A, B)	Install Under 10 CFR 50.59	LR Section
Transition to upgrade fuel assembly design	A	(1)	2.8.1
Nuclear steam supply system (NSSS) setpoints	A		2.4.1
NSSS settings and scalings	B	X	2.4.1
Balance-of-plant (BOP) setpoints	A		2.4.1
BOP settings and scalings	B	X	2.4.1
Increase Technical Support Center shielding and modify heating, ventilation, and air conditioning system to ensure compliance within limits	A	X	2.7.1
Revise the pressurizer level program span	A	X	2.4.2
Reduce the pressurizer safety valve lift settings	A		2.8.5.2.1

Modification	Category (A, B)	Install Under 10 CFR 50.59	LR Section
Removal of pressurizer backup heater actuation on high pressurizer level deviation	A	X	2.4.2
Revise pressurizer relief tank water level alarm setpoints	B	X	2.5.2
Reduce the overpressure mitigation system power-operated relief valve setpoint	A		2.8.4.3
Revise allowable ranges of boron concentrations in RWST, boric acid storage tank, and accumulators	A		2.8.5.6.3
Install reach rods on safety injection valves 3-867 and 4-867	A	X	2.10.1
Implementation of lead/lag on the steamline pressure signal	A	X(3)	2.6.3.2
Upgrade MSIV's and MSCV's	A	X	2.5.5.1
Reduce setpoints of two highest set MSSV's	A		2.8.5.2
Replace high pressure (HP) turbine rotor, electro-hydraulic control system, high lift control valves, and install digital controls	B		2.5.1.2.2
Upgrade turbine gland sealing and spillover	B	X	2.5.3.3
Replace main condenser tube bundles and water boxes	B	X	2.5.5.2
Replace condenser cleaning system	B	X	2.5.5.2
Replace turbine plant cooling water Heat Exchangers	B	X	2.5.4.2
Replace condensate pumps and institute automatic turbine runbacks on loss of condensate pump or heater drain pump(s)	B	X(3)	2.5.5.4
Replace feedwater pump rotating assemblies and adjust pump trip setpoints for staggered configuration	B	X(3)	2.5.5.4
Modify and relocate backup feedwater isolation valves and add backup feedwater isolation valves on the feedwater bypass lines	A	X	2.6.3.2
Modify main and bypass feedwater control valves	B	X(3)	2.5.5.4
Add leading edge flowmeters in feedwater system	B	X(2)	2.4.4
Modify steam generator blowdown flow and main steamline pressure instrumentation to improve measurement uncertainty	B	X	2.4.4
Replace moisture separator reheaters	B	X	2.5.5.1
Replace feedwater heaters #5 and #6	B	X(3)	2.5.5.4
Modify feedwater heater #5 drain line piping and	B	X	2.1.8

Modification	Category (A, B)	Install Under 10 CFR 50.59	LR Section
replace extraction steam piping from HP turbine to feedwater heater #6 on Unit 3.			
Rerate high pressure feedwater piping and rerate or replace steam jet air ejector condenser	B	X	2.5.5.4
New or modified jet impingement shields	A	X	2.5.1.3
Modify and refurbish auxiliary feedwater pumps	A	X	2.5.4.5
Remove auxiliary feedwater travel stops	A		2.5.4.5
Addition of supplemental heat exchanger for spent fuel pool cooling system	B	X	2.5.4.1
Main generator upgrade including rewinding stator, new rotor, current transformers, hydrogen coolers, and exciter air cooler	B	X	2.3.3
Iso-phase bus duct modifications	B	X	2.3.3
Reduce emergency diesel generator voltage and frequency tolerances	A		2.3.3
Reduce 480-volt load center voltage tolerance	B		2.3.3
Main step up transformers cooling and tap changer modifications	B	X	2.3.3
Replace unit auxiliary transformers	B	X	2.3.3
Switchyard modifications	B	X	2.3.2
Upgrade main steam, condensate, feedwater and component cooling water supports	A	X	2.2.2.2
Heater drain system digital upgrade and control valve upgrades	B	X	none
control rod drive mechanism cooling fan motor upgrade	B	X	2.7.7
Emergency Containment Cooler logic	A	X	Letter dated 7/22/11

Category Key:

A. Required to support safety analyses

B. Required to support operation at uprated power level

1. The enrichment of this fuel would be limited to 4.5 percent by weight uranium-235 until the enrichment limit is increased to 5 percent through this license amendment request (LAR).
2. Installation of the leading edge flow meter will be screened under Title 10 of the *Code of Federal Regulations* (10 CFR) 50.59, "Changes, tests and experiments." It will not be used for conformance to licensed power level until this LAR is approved by NRC.
3. Modification can be installed under 10 CFR 50.59. Requires new main steamline break methodology approval by the NRC prior to EPU operation.

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, "Reactor Vessel Material Surveillance Program Requirements," provides the NRC staff's requirements for the design and implementation of the RV material surveillance program. The Nuclear Regulatory Commission (NRC) staff's review primarily focused on the effects of the proposed extended power uprate (EPU) on the licensee's RV surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on (1) 10 CFR Part 50, Appendix A, "General Design Criteria [GDC] for Nuclear Power Plants," GDC-14, "Reactor Coolant Pressure Boundary," 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) 10 CFR Part 50, Appendix A, GDC-31, "Fracture Prevention of Reactor Coolant Pressure Boundary," which requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the RV beltline region; and (4) 10 CFR 50.60, "Acceptance criteria for fracture prevention measures for lightwater nuclear power reactors for normal operation," which requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria are contained in NRC's NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [Light Water Reactor] Edition" (Standard Review Plan or SRP) Section 5.3.1, "Reactor Vessel Materials."

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

The licensee noted that the GDC used during licensing of Turkey Point Nuclear Plant (PTN) Units 3 and 4 predate the GDC provided in the current 10 CFR Part 50, Appendix A. The PTN Units 3 and 4 GDC were developed based on the 1967 Atomic Energy Commission Proposed GDC. PTN GDC-34, "Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention," states that:

> The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failure. Consideration is given (a) to the provisions for control over service temperature

and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes.

The NRC staff notes that PTN GDC-34 is essentially equivalent to the current GDC 31, and therefore the staff finds it is an acceptable regulatory criterion to be used by the licensee when evaluating RV integrity.

Licensee Evaluation

Reactor Vessel Fluence

The PTN Units 3 and 4, Extended Power Uprate Licensing Report (LR), contained in Attachment 4 to Reference 1, Section 2.1.1.2.5 states that the reactor vessel fluence projections and updated capsule fluence values were generated for the EPU following the guidance of Regulatory Guide (RG) 1.190, “Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence.” The licensee cited WCAP-16083-NP-A, Revision 0, “Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry,”[5] as the specific methodology used for the fluence analysis. Fluence projections for the RV inner surface for 48 effective full power years (EFPY) considering EPU, were provided in LR Tables 2.1.1-1 and 2.1.1-2. Fluence projections for the 1/4T and 3/4T locations are provided in Tables 2.1.2-3, 2.1.2-4, 2.1.2-5, and 2.1.2-6 for PTN Units 3 and 4.

Reactor Vessel Materials Surveillance Program

The licensee provided a description of the impact of EPU on the reactor vessel materials surveillance program in LR Section 2.1.1. The licensee included a surveillance capsule withdrawal schedule accounting for the EPU. The licensee evaluated the surveillance capsule withdrawal schedule based on the projected end of life neutron fluence accounting for the EPU. The licensee also indicated that the reactor vessel inlet temperature (T_{COLD}) after EPU would remain in the range of 525 degrees Fahrenheit (°F) to 590 °F required for the equations and methodology of RG 1.99, Revision 2, “Radiation Embrittlement of Reactor Vessel Materials,” to remain valid, without adjustments for temperature effects.

ASTM E 185-82, “Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels,” recommends that if the maximum shift in ΔRT_{NDT} is greater than 200 °F, as it is for PTN Units 3 and 4, then five capsules should be withdrawn and tested. PTN meets this criterion. The only change to the surveillance capsule withdrawal schedule to account for EPU is for capsule X_4. Prior to the EPU, per the most recent approved revision to the withdrawal schedule, this capsule was to be withdrawn at 33.2 EFPY.[6] In the initial recommended withdrawal schedule considering EPU, provided in LR Table 2.1.1-6, the licensee proposed to withdraw the last capsule, X_4, between 31.4 and 47.8 EFPY, which the licensee

[5] ML061600256
[6] ML062480165

stated met the requirement that the fluence for the last capsule be at least once and no greater than twice the projected RV end-of-life (EOL) fluence. However, in response to request for additional information (RAI) CVIB-1.1, by letter dated March 9, 2011,[7] the licensee provided a withdrawal date of the nearest refueling outage to 35.8 EFPY at an estimated fluence of 8.14×10^{19} neutrons per square centimeters (n/cm^2). The licensee indicated fluence is equivalent to the 80 year (67 EFPY) RV fluence.

NRC Technical Evaluation

Reactor Vessel Fluence

RG 1.190 describes acceptable ways to calculate reactor vessel neutron fluence. RG 1.190 states that fluence calculations should adhere to NRC-approved methodology and provides acceptable qualification criteria. In the NRC staff's safety evaluation for WCAP-16083-NP-A, the NRC staff concluded that the transport calculations and the dosimetry cross sections are consistent with RG 1.190 and are, therefore, acceptable. Thus, the NRC staff finds the EOL fluence projections for PTN Units 3 and 4 to be acceptable.

Reactor Vessel Materials Surveillance Program

ASTM E 185-82 recommends that for a RV with a predicted transition temperature shift at the vessel inside surface of > 200 °F, the vessel should have a minimum of five surveillance capsules installed. The NRC staff issued a license amendment allowing an integrated surveillance program for PTN Units 3 and 4 via letter dated April 22, 1985.[8] With the integrated surveillance program five capsules need not be withdrawn from each unit as long as the five withdrawal times are covered between the two units. In the PTN Units 3 and 4 recommended withdrawal schedule, four capsules from Unit 3 and three capsules from Unit 4 are being withdrawn to cover the five withdrawal times recommended in ASTM E185. ASTM E 185-82 recommends that for a reactor with five surveillance capsules installed, the last capsule should be withdrawn at a neutron fluence greater than once but less than twice the peak EOL vessel fluence. The NRC staff verified from LR Tables 2.1.1-4 and 2.1.1-5 that the maximum shift in ΔRT_{NDT} is greater than 200 °F for PTN Units 3 and 4. Since the estimated neutron fluence at withdrawal for the last capsule (X_4) at approximately 35.8 EFPY is between one and two times the projected peak RV fluence for PTN Units 3 and 4 of 6.377×10^{19} n/cm^2, consistent with the requirement of ASTM E185-82 for the last capsule, the proposed withdrawal fluence and EFPY is acceptable.

Conclusion

Reactor Vessel Fluence

Since the method of calculating the EOL neutron fluence for the RV, which is used as the basis for the surveillance program, adjusted reference temperature, upper shelf energy (USE), pressure-temperature (P-T) limit, and pressurized thermal shock calculations, meets the

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[7] ML110700068
[8] ML013370393

applicable regulatory guidance of RG 1.190, the NRC staff finds the licensee's neutron fluence methodology acceptable.

Reactor Vessel Materials Surveillance Program

Since the surveillance capsule withdrawal schedule for PTN Units 3 and 4, modified to account for EPU, meets ASTM E 185-82 criterion and, thus, meets 10 CFR Part 50, Appendix H, thereby meeting 10 CFR 50.60, the NRC staff finds the surveillance program acceptable to support the EPU.

2.1.2 Pressure-Temperature 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, "Fracture Toughness Requirements," which specifies fracture toughness requirements for ferritic components of the reactor coolant pressure boundary;

- 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, "Pressure-Temperature Limits, Upper Shelf Energy, and Pressurized Thermal Shock," and other guidance is provided in Matrix 1 of the NRC's review standard (RS), RS-001, "Review Standard for Extended Power Uprates," Revision 0, December 2003,.

Appendix G to 10 CFR Part 50 provides the NRC 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 foot-pounds (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) 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.

For evaluations of low-upper shelf toughness, SRP, Section 5.3.2, under review procedures states that in addition to the ASME Code, Regulatory Guide 1.161, "Evaluation of Reactor Pressure Vessels with Charpy Upper-Shelf Energy Less Than 50 Ft-Lb," provides an acceptable methodology for the performance of analyses intended to meet the provisions for additional analysis specified in 10 CFR Part 50, Appendix G, paragraph IV.A.1.a (which addresses low-upper shelf toughness).

As noted in Section 2.1.1, PTN Units 3 and 4 predate the GDC of 10 CFR Part 50 Appendix A. The licensee cited PTN GDC-34, which the NRC staff found to be equivalent to GDC 31 and, therefore, is an acceptable regulatory criterion to be used by the licensee when evaluating RV integrity.

The licensee's regulatory evaluation also notes that according to the Updated Final Safety Analysis Report, Section 16.3.1, PTN Units 3 and 4 meet the requirements of 10 CFR Part 50, Appendix G with respect to the P-T limits and RV USE.

Upper Shelf Energy

Licensee Evaluation

USE Projections

The licensee projected the USE values for 48 EFPY using the fluence values revised for EPU. The fluence values at a postulated flaw depth at a location one quarter of the vessel wall thickness from the clad/base metal interface (1/4T) were used and the USE projection was performed in accordance with RG 1.99, Revision 2. The licensee's projection shows the USE of all the beltline materials remains above 50 foot-pounds (ft-lb) at 60 years, except for the lower shell (LS) to intermediate shell (IS) circumferential weld (Weld SA-1101) and IS to upper shell (US) welds for both units.

Equivalent Margins Analysis

For the PTN Units 3 and 4 reactor vessel materials for which the USE is projected to fall below 50 ft-lb prior to 48 EFPY, the licensee stated in LR Section 2.1.2.2.5 that they performed an equivalent margin analysis (EMA). The revision to the EMA accounting for EPU and 48 EFPY was submitted to the NRC staff as a supplement to the EPU LAR on December 21, 2010.[9] Since the original fluence projections considering EPU were revised after the issue of the December 21, 2010, letter in January 2010, the licensee provided an additional supplement to the EPU LAR explaining how a slight change in the neutron fluences considering EPU were reconciled to the previous EMA.[10] The revised EMA used the methodology of the ASME Code, Section XI, Appendix K, 1998 edition with addenda through 2000. The revised EMA also used a model for the weld material fracture resistance identical to that used in previous versions of the EMA for PTN, Units 3 and 4, and approved by the NRC staff by letters dated October 19, 1993, "Turkey Point Units 3 and 4 – Review of Babcock and Wilcox Owner's Group Materials

[9] ML103610321
[10] ML103210231

Committee Reports – Upper Shelf Energy,"[11] and March 29, 1994, "Acceptance for Referencing of Topical Report BAW-2178P, Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W [Babcock and Wilcox] Owner's Reactor Vessel Working Group for Level C & D Service Loads."[12] The revised EMA was performed on the circumferential weld with the lowest projected USE value, which was the IS to LS circumferential weld for both Units.

For the Service Level A & B loadings, the licensee's calculated lower-bound J-integral resistance value and applied J-integral values at a crack extension of 0.1 inches ($J_{0.1}$) reported in letter dated March 12, 2010, are 602 pounds per inch (lb/in) and 141 lb/in, identical to the values stated in letter dated December 21, 2010. By letter dated December 21, 2010, the licensee concluded that the acceptance criteria of ASME code, Section XI, Appendix K have been met because: 1) the applied J-integral (J_1) is less than the J-integral resistance of the material ($J_{0.1}$) at a ductile flaw extension of 0.1 inch (in), with a safety factor of 1.15 on pressure and 1.0 on thermal loading, and 2) with a factor of safety on pressure of 1.25 and 1.0 on thermal loading, flaw extensions are ductile and stable since the slope of the applied J-integral curve is less than the slope of the lower-bound J-integral resistance curve at the point where the two curves intersect.

For Service Level C & D loadings, the main steamline break was identified as the limiting transient for PTN Units 3 and 4. The licensee determined the applied stress intensity factors K_I for the Service Level C & D loadings using the computer code PCRIT. The licensee determined a K_I for the RV base metal, a separate K_I factor attributable to the vessel cladding, and the total K_I (K_{Itotal}).

At a crack extension of 0.1 in, the licensee's calculated lower bound J-integral resistance and applied J-integral values as stated in letter dated March 12, 2010, are 743 lb/in and 243 lb/in, virtually identical to the values of 742 lb/in and 243 lb/in as stated in letter dated April 22, 1985. The licensee's evaluation of Service Level C & D loadings in letter dated December 21, 2010, concluded the acceptance criterion of the ASME Code, Section XI, Appendix K, paragraphs K-2300 and K-2400 are met because: 1) With a factor of safety of 1.0 on loading, at a flaw extension of 0.1 in, the applied J-integral (J_1) is far less than the lower-bound J-integral resistance ($J_{0.1}$); 2) Flaw extensions are ductile and stable since the slope of the applied J-integral curve is less than the slopes of both the lower bound and mean J-integral resistance curves at the points of intersection; and 3) Since the flaw extension of less than 0.01 in represents less than 1 percent of the wall thickness, the licensee concluded the criterion of K-2400 for flaw extension less than 75 percent of the wall thickness for Service Level D loadings is also met.

The licensee concluded based on the EMA that the PTN Units 3 and 4 IS to LS circumferential welds satisfy the acceptance criteria of Appendix K of Section XI of the ASME Code for projected low USE at 48 EFPY under EPU conditions. The licensee, therefore, concluded that since the IS to LS circumferential weld is the bounding material for each Unit, all PTN Units 3 and 4 reactor vessel materials meet the requirements of 10 CFR Part 50, Appendix G, with regards to low USE.

[11] ML9310250159
[12] ML9404250026

NRC Technical Evaluation

USE Projections

The NRC staff performed a confirmatory calculation of the licensee's projected USE values with the neutron fluence values provided by the licensee and using the method of RG 1.99, Revision 2. To support our confirmatory calculation, the NRC staff also checked the unirradiated USE values against the values for the corresponding materials in the NRC's Reactor Vessel Integrity Database (RVID). The unirradiated USE values match those in the RVID; however, not all the materials listed in the LR are in the RVID since some of the materials are extended beltline materials, or those that will exceed a neutron fluence of 1 x 10^{17} n/cm^2 during the period of extended operation. Also, the US to IS welds have no unirradiated RT_{NDT} data in the RVID. The NRC staff's projected USE values were very similar to the licensee's values, with the licensees projected decrease in USE being slightly greater, and the licensee's EOL USE values slightly lower in all cases. All materials have an EOL USE greater than 50 ft-lb except the US to IS circumferential weld, and the IS to LS circumferential weld, for both units. These materials are addressed by the EMA as discussed below.

Equivalent Margins Analysis

By letter dated April 19, 2001,[13] the NRC staff previously reviewed and approved a version of the EMA for 48 EFPY that was submitted in conjunction with the PTN Units 3 and 4 license renewal applications. The NRC staff documented its acceptance of the EMA in Section 4.2.2 of the "Safety Evaluation Report related to the License Renewal of Turkey Point Nuclear Plant Units 3 & 4," (NUREG-1759).[14] The NRC staff reviewed the revised EMA in letter dated December 21, 2010, and determined that the methodology used is identical to the methodology in letter dated April 19, 2001, with the exception that the December 21, 2010, methodology used a more sophisticated method to determine the portion of the stress intensity factor attributable to cladding. With respect to the J-integral resistance (the material fracture toughness, J_R), the ASME Code, Section XI, Appendix K, paragraph K-3300 specifies that the J_R curve must be generated based on accepted test procedures, a database obtained from the same class of material, or an indirect method provided the method is justified for the material. By letter dated October 19, 1993, the NRC staff verified that the J_R model used by the licensee in the updated EMA is the same as the model described in a previous EMA report for PTN with which the NRC staff concurred. By letter dated March 29, 1994, the NRC staff also has previously approved a topical report for low-upper shelf evaluation under Level C & D loading, which used the same J_R model applicable to Babcock and Wilcox manufactured RV's. The NRC staff performed a confirmatory calculation of the J_R curve of the material using the methodology of Section 3 of Attachment 1 in letter dated December 21, 2010. In the confirmatory calculation, the NRC staff used the RV inner diameter neutron fluence for the IS to LS circumferential weld from Table 2-1 of the reconciliation document as stated in letter dated November 12, 2010. The NRC staff used the copper content of 0.23 weight percent for this weld that was provided in letter dated December 21, 2010. The NRC staff notes the neutron fluence provided in the reconciliation document for the cladding to base metal interface of the IS to LS circumferential weld is identical to the inner diameter neutron fluence provided in the EPU LR for this weld

[13] ML011170147
[14] ML021280532

(5.739×10^{19} n/cm^2). For the Service Level A & B loadings, the NRC staff obtained a lower-bound J_R value at a crack extension of 0.1 inches ($J_{0.1}$) of 602 lb/in, identical to the licensee's value provided in letter dated November 12, 2010. For the Service Level C & D loadings, the NRC staff obtained a lower-bound $J_{0.1}$ value of 742 lb/in, which is virtually identical to the licensee's result of 743 lb/in in letter dated November 12, 2010. The NRC staff, therefore, finds the licensee's $J_{0.1}$ values are acceptable.

The NRC staff also performed confirmatory calculations of the applied J-integral values at 0.1 in crack extension (J_1) for both the Service Level A and B loadings and Service Level C & D loadings using the methodology of the ASME Code, Section XI, Appendix K. The NRC staff notes that the J_1 value did not change as a result of the EPU for either Service Level A & B or Service Level C & D conditions.

The licensee referenced the 1998 edition of the ASME Code, Section XI with addenda through 2000, with respect to the methodology used for the revised EMA. Appendix G to 10 CFR Part 50, paragraph IV.A.1.a, requires that such analyses use the latest edition and addenda of the ASME Code incorporated by reference into 10 CFR 50.55a (b)(2) at the time the analysis is submitted. The latest edition of the ASME Code, Section XI (Division 1) incorporated by reference into 10 CFR 50.55a at the time of the submittal is the 2004 edition. The NRC staff compared the procedures of Section XI, Appendix K for the two different ASME Code edition and addenda and found no significant differences. However, the NRC staff noted minor differences in some of the elastic modulus values from Table TM-1 of the ASME Code, Section II-D. The difference in modulus values was small and had no significant effect on the NRC staff's confirmatory calculations. However, the NRC staff requested the licensee to reconcile the differences between the two ASME Code editions as they affect the low-upper shelf toughness evaluation In the licensee's response dated March 9, 2011, RAI CVIB-1.2, the licensee provided the results of their reconciliation of the two ASME Code editions. The licensee found the only difference to be in some of the elastic modulus values for the base metal and cladding materials from Section II, Part D of the ASME Code. The changes to the elastic modulus values were minor (less than 0.5 percent), therefore, the effect on the EMA calculations was not significant. The licensee found no changes to Section XI, Appendix K between the two ASME Code editions, other than the addition of International System units in the 2004 edition, which also does not affect the EMA calculations, since the calculations used U.S. customary units. Therefore, since the NRC staff's independent evaluation of the differences in the two ASME Code editions agreed with the licensee's evaluation of the differences, and the differences have no significant effect on the EMA calculations, as confirmed by the NRC staff's calculation, the staff considers RAI CVIB-1.2 resolved.

Service Level A & B Loadings

The NRC staff reviewed the methodology used by the licensee to calculate the applied J-integral (J) for Service Level A & B loadings, and finds that it is consistent with the ASME Code, Section XI, Appendix K, 2004 edition.

The NRC staff confirmed the licensee's J_1 value at a safety factor on pressure of 1.15 of 141 lb/in. The $J_{0.1}$ value of 602 lb/in calculated by the NRC staff is greater that the J_1 value of 141 lb/in calculated by the staff, thus meeting the acceptance criterion from the ASME Code, Section XI, Appendix K, of $J_{0.1} > J_1$. The NRC staff graphed J at a safety factor of 1.25 on

pressure for the Service Level A & B conditions, and the applicable mean and lower bound J_R values, versus crack extension. Based on the graph, the NRC staff confirmed that with a factor of safety of 1.25 on pressure and 1.0 on thermal loading, the slope of the J curve is less than the slope of the J_R curve at the intersection of the two curves, indicating that flaw extensions are ductile and stable thus meeting the acceptance criteria of the ASME Code, Appendix K, paragraph K-2200.

Service Level C & D Loadings

For Service Level C & D loadings, the ASME Code, Section XI, Appendix K, subparagraph K-5210 requires that stress intensity factors K_I shall be calculated as a function of flaw depth "a" for each applicable stress component due to internal pressure, radial thermal gradients through the vessel wall, and cladding/base metal differential thermal expansion. However, Appendix K does not specify the specific transients with which the Service Level C & D loadings are associated or provide equations for calculating the resulting K_I values. Therefore, the NRC staff verified that the main steamline break was accepted by the staff as the limiting transient for the PTN in letter dated March 29, 1994, which documented the NRC staff's acceptance for referencing a generic EMA for Service Level C & D loadings applicable to RVs fabricated by Babcock & Wilcox.

The NRC staff reviewed the licensee's methodology for evaluating Service Level C & D loadings and determined that it is generally consistent with the methodology described in the ASME Code, Section XI, Appendix K. The NRC staff noted two minor apparent deviations from the ASME Code, Section XI, Appendix K procedures as discussed below.

- One apparent deviation was that the equation for calculating the applied J-integral did not appear to adjust for small scale yielding in accordance with subparagraph K-5210 of the ASME Code, Section XI, Appendix K. In the licensee's response to RAI CVIB-1.3 dated March 9, 2011, the licensee indicated that the PCRIT computer code incorporated the adjustment for small-scale yielding into the K_{Itotal} term consistent with the ASME Code Appendix K. The NRC staff finds the licensee's response to RAI CVIB-1.3 to be acceptable since it explains how small-scale yielding was incorporated, thus considers this RAI to be resolved.

- The licensee performed a check on tensile instability using the procedure of the ASME Code, Section XI, Appendix K, paragraph K-5300, for a circumferential flaw. The NRC staff reviewed the licensee's calculation and finds it is was performed in accordance with paragraph K-5300. The NRC staff also independently verified the licensee's calculation. The NRC staff notes that paragraph K-5300 states that the material properties including yield strength should account for the effects of temperature and fluence. The tensile instability calculation uses as an input the material flow stress σ_o, which is the average of the yield and ultimate strengths. For the yield strength, the licensee used the ASME Code value which accounts for temperature but not fluence. The NRC staff finds this to be conservative and, therefore, acceptable because neutron fluence generally increases the material yield strength, which would tend to increase the material flow stress. The licensee also used $\sigma_o = \sigma_y$, which is also conservative since the flow stress would generally be larger than the yield stress.

The NRC staff determined a J_1 value of 243 lb/in, which is identical to the licensee's value; therefore, the staff considers the licensee's calculation to be confirmed. The $J_{0.1}$ value of 742 lb/in calculated by the NRC staff is greater than the J_1 value of 243 lb/in calculated by the staff, thus meeting the acceptance criterion from the ASME Code, Section XI, Appendix K, of $J_{0.1} > J_1$. The NRC staff graphed J for Service Level C & D loadings versus the applicable J_R at a safety factor on loading of 1.0. The graph shows that the slope of the J curve is less than the slope of the J_R curve at the intersection of the two curves, indicating that flaw extensions are ductile and stable thus meeting the acceptance criteria of the ASME Code, Appendix K, paragraph K-2300 for Service Level C & D loadings. The NRC staff's graph also shows the curves intersect at less than 0.01 in. crack extension, resulting in a total flaw depth after ductile flaw extension of less than 0.785 in, which is far less than 75 percent of the vessel wall thickness, thus meeting the acceptance criteria of the ASME Code, Section XI, Appendix K, paragraph K-2400 for Service Level D loadings.

Equivalent Margins Analysis - Summary

The NRC staff reviewed the methodology used to perform the EMA, and finds it is consistent with the methodology of the ASME Code, Section XI, Appendix K. Since RG 1.161 essentially endorses the methods of the ASME Code, Section XI, Appendix K, with respect to evaluation of the Service Level A, B, C and D loadings, the licensee's methodology for addressing these loadings meets the recommendations of RG 1.161. The model used for the fracture resistance of the material used by the licensee is different than the model described in RG 1.161, but was developed specifically for vessels fabricated by B&W, and was previously approved by the NRC staff in letters dated October 19, 1993, and March 29, 1994. With respect to identification of the limiting transients for Service Level C & D loadings, the ASME Code, Section XI, Appendix K does not provide any guidance. The selection of the main steamline break as the limiting transient for PTN Units 3 and 4 has been previously reviewed and approved by the staff by letter dated March 29, 1994. The NRC staff also performed a calculation of the applied J-integral versus J-integral resistance (toughness) that confirmed the licensee's values.

<u>Pressure-Temperature Operating Limits</u>

<u>Licensee Evaluation</u>

To support the EPU, the licensee prepared new P-T limits valid through 48 EFPY. Revised heatup curves were provided as technical specifications (TS) Figure 3.4.2, and the revised cooldown curves were provided as TS Figure 3.4.3. The same figures were provided as Figure 2.1.2-1 and 2.1.2-2 of the LR. The licensee provided a markup of TS Bases 3/4.4.9, which indicates that the licensee used the methodology of WCAP-14040-NP-A, Revision 2, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS [Reactor Coolant System] Heatup and Cooldown Curves."[15] The licensee also referenced "WCAP-15092, Revision 5, "Turkey Point Units 3 and 4 WOG [Westinghouse Owners Group] Reactor Vessel 60-Year Evaluation Minigroup Heatup and Cooldown Limit Curves for Normal Operation," as the basis for the current P-T limits, but did not provide the report with the EPU submittal. In a conference call on January 26, 2011, the licensee clarified that the WCAP-15092, Revision 5 report did not account for EPU, and that the methodology used to

[15] ML9601190176

develop the revised P-T limits was the same as described in WCAP-15092, Revision 3.[16] The minor changes from Revision 3 to Revision 5 did not affect the P-T limit curves.

Adjusted Reference Temperature (ART) and Identification of Limiting Material

The ART for the beltline materials used as input to the new P-T curves were determined using the revised projected fluence accounting for EPU. In LR Tables 2.1.2-3 through 2.1.2-6, the licensee provided the inputs and results for the ART calculations for the 1/4T and 3/4T locations for 48 EFPY. The method of RG 1.99, Revision 2, was used to determine the ART. For both units, the IS to LS weld has the highest ART at 231 °F at 1/4T and 192 °F at the 3/4T location. For the IS forging, LS forging and the IS to LS weld, Tables 2.1.2-3 through 2.1.2-6 include values determined using both RG 1.99, Revision 2, Position 1.1 (tables) and 2.1 (surveillance data). LR Section 2.1.2.1 indicates that an exemption request for the use of alternate weld material initial properties based on Framatome ANP topical reports BAW-2308, Revisions 1-A and 2-A, was approved on March 11, 2010.

LR Section 2.1.2.2.5 identified the limiting RV materials with respect to P-T limit development and provided the 1/4T and 3/4T ART values for these materials The limiting material with respect to circumferential flaws for PTN Units 3 and 4 is the IS to LS circumferential weld (without using surveillance data). The 1/4T and 3/4T ART values for this material are 231 °F and 192 °F, respectively. The limiting material with respect to axial flaws for PTN Units 3 and 4 is the Unit 3 US forging. The 1/4T and 3/4T ART values for this material are 141 °F and 124 °F, respectively. The limiting ARTs provided are based on RG 1.99, Revision 2, Position 1.1.

10 CFR 50 Appendix G Minimum Temperature Requirements

WCAP-15092, Revision 3 provided the most limiting RT_{NDT} for the closure head flange for PTN Unit 3 of 44 °F, and -1 °F for Unit 4. On that basis, in WCAP-15092, Revision 3 the licensee indicated that they conservatively set the bolt-up temperatures at 71 °F for Unit 3 and 70 °F for Unit 4. In the TS bases markups provided with the EPU application, the licensee provided revised Tables B 3/4.4-1 and B3/4/4-2 that shows the closure head flange RT_{NDT} changed from 44 °F to -50 °F for Unit 3 and 4 °F to -50 °F for Unit 4. The change in the closure head flange RT_{NDT} causes the vessel shell flange for Unit 4 of -1 °F to become the limiting material in the closure flange region that is highly stressed by bolt preload. The licensee's P-T curves in TS Figures 3.4-2 and 3.4-3 show a bolt-up temperature of 70 °F, and a minimum temperature for criticality of 260 °F on the heatup curve (which a note states in based on the inservice hydrostatic test requirement). The curves also show the pressure is 621 pounds per square inch absolute or less at temperatures below 119 °F, for all heatup and cooldown rates.

Calculation of P-T Limits

The licensee provided figures with revised P-T limits for 60 degrees Fahrenheit per hour (°F/hr) and 100 °F/hr heatup rates, and 20, 40, 60, and 100 °F/hr cooldown rates. In response to RAI CVIB-1.4f, letter dated March 9, 2011, the licensee indicated that the revised P-T limits were developed based on the 1995 Edition through 1996 Addenda of the ASME Code, Section XI, Appendix G and provided a revised marked up TS bases 3/4.4.9 indicating that the P-T limits

[16] ML003732201

are based on the K_{Ia} methodology of the 1995 Edition through 1996 Addenda of the ASME Code, Section XI, App. G. Since the licensee corrected the year edition referenced in the TS for the P-T curve methodology, the NRC staff finds RAI CVIB-1.4f to be resolved.

NRC Technical Evaluation

Adjusted Reference Temperature and Identification of Limiting Material

The NRC staff performed a confirmatory calculation of the ART of all the baseline materials for the PTN Units 3 and 4 RV's at 48 EFPY. The NRC staff used the methodology of RG 1.99, Revision 2 to perform the calculation. The NRC staff checked the copper and nickel values and initial RT_{NDT} values for the non-weld materials (base materials) against the values for the corresponding materials in the RVID. For the weld materials, the NRC staff confirmed that the initial RT_{NDT} values and initial margin σ_i values for the weld materials are consistent with the values specified in BAW-2308, Revision 2-A,[17] Table 9, since the staff approved a plant-specific exemption allowing PTN to use that methodology to determine the initial RT_{NDT} of the weld materials. By letter dated March 11, 2010,[18] the NRC staff also verified the plant-specific exemption has been issued and is valid. The NRC staff notes that there is no data in the RVID for the extended beltline materials, consisting of the inlet nozzles, outlet nozzles, and inlet/outlet nozzle welds. The initial RT_{NDT} values for the inlet/outlet nozzle welds match the values from BAW-2308, Revision 2-A for heat #299L44 and "other heats."

The NRC staff used the vessel inner diameter fluences provided by the licensee in LR Tables 2.1.1-1 and 2.1.1-2 to independently calculate the 1/4t and 3/4t fluences for each material using the attenuation equation of RG 1.99, Revision 2. Additionally, the NRC staff independently verified the licensee's chemistry factor values by using the chemistry values supplied by the licensee in conjunction with the chemistry factor tables of RG 1.99, Revision 2. The NRC staff did not perform a confirmatory calculation of the chemistry factors determined using surveillance data, because the applicant did not use the surveillance data to determine the limiting ART values used to develop the P-T curves.

In RAI CVIB-1.4g, the NRC staff requested the licensee provide information related to the determination of the ART for the limiting materials. In Part 1 of the RAI the staff requested supporting data for, and the calculation of, the chemistry factors for those RV materials that have surveillance data. By letter dated March 9, 2011, in response to RAI CVIB-1.4g, Part 1, the licensee identified the three materials in the surveillance program, which are the IS forging, the LS forging, and weld metal heat #71249 which is used in IS to LS shell weld. The licensee provided the calculation of the chemistry factors (CFs) from the surveillance data for these materials, including the fluence, fluence factor, measured ΔRT_{NDT} of the surveillance material, and the calculation based on the method of RG 1.99, Revision 2, Position 2.1. In Part 3, the NRC staff requested the credibility evaluation of the surveillance data. The licensee provided the credibility evaluation based on the five credibility criteria for RG 1.99, Revision 2, which resulted in a determination that the base metal surveillance data was credible but the weld metal surveillance data was not credible. The weld metal data was determined to be noncredible due to the scatter of the surveillance data about the best-fit line exceeding 28 °F for

[17] ML081270388
[18] ML100150599

some of the data points. For both the forgings and the weld material, the CF determined through the table in RG 1.99, Revision 2 (Position 1.1) was larger and, therefore, more conservative than the CF determined using surveillance data. For the weld metal, the licensee used the RG 1.99, Revision 2, Position 1.1 (non-surveillance) values for determining the ART used in the P-T curve development. The NRC staff notes that the limiting material with respect to axial flaws for the P-T curve development is the US forging which is not represented by surveillance material. In Part 2, the NRC staff asked for the copper and nickel values for the surveillance materials. In response, the licensee provided the copper and nickel values for the surveillance weld materials from heat #71249 from the PTN Units 3 and 4 and Davis-Besse Nuclear Power Station surveillance programs. In Part 4, the NRC staff asked whether the ratio procedure of RG 1.99, Revision 2, Position 2.1 was used in the chemistry factor calculations. The licensee indicated that the ratio procedure was used to adjust for differences between the surveillance weld chemistry and the IS to LS weld chemistry. The NRC staff finds the licensee's response to RAI CVIB-1.4g is acceptable because the information provided demonstrated the licensee conservatively accounted for the surveillance data in the determination of the ART for the PTN Unit 3 and 4 RV. The NRC staff, therefore, finds RAI CVIB-1.4g to be resolved.

Pressure Correction Factors

TS Figures 3.4-2 and 3.4-3 note that the curves are without margin for instrument error, but the supporting information for the P-T limits did not specify if a correction factor has been applied to account for the difference in pressure between the RV and the measurement location. In RAI CVIB-1.4d, the NRC staff requested this information. In letter dated March 9, 2011, the licensee indicated that the P-T limit curves do not include margin for the pressure difference between the RV pressure and the pressure at the measurement location. The licensee further stated that the PTN Units 3 and 4 overpressure mitigation system (OMS) power-operated relief valve setpoint, which prevents the P-T limits from being exceeded, accounts for a pressure differential of 57.4 pounds per square inch between the pressure measurement location and the RV, and that since the OMS setpoint includes the impact of the pressure differential, it is not necessary to include this impact in the P-T limit curves. Based on this information, the NRC staff finds RAI CVIB-1.4d to be resolved.

10 CFR Part 50 Appendix G Minimum Temperature Requirements

The NRC staff reviewed the minimum temperature requirements for PTN Units 3 and 4 RV P-T limits against the requirements of 10 CFR Part 50 Appendix G. These requirements cover hydrostatic pressure and leak tests and normal operation (including heatup and cooldown), with both the core critical and core not critical, and are summarized in Table 1 of 10 CFR Part 50, Appendix G. Most of the minimum temperature requirements are derived from the highest reference temperature of the closure flange region of the vessel that is highly stressed by bolt preload. Since the licensee's markup of TS Bases 3/4.4.9 indicated a change to the highest reference temperature in the closure flange region, in RAI CVIB-1.4e the NRC staff requested the basis for the change from 44 °F to -50 °F for the closure head flange noted above, which was formerly the limiting material. By letter dated March 9, 2011, in response to RAI CVIB-1.4e, the licensee indicated the change was due to RV head replacement. The NRC staff finds RAI CVIB-1.4e is resolved. As a result, the vessel shell flange for Unit 4 becomes the limiting material in the closure flange region with an RT_{NDT} of -1 °F. The NRC staff checked the minimum temperature requirements shown on the proposed revised P-T curves based on the

revised limiting RT_{NDT} of the closure flange region and finds that the PTN Units 3 and 4 P-T limits meet the minimum temperature requirements of 10 CFR Part 50 Appendix G.

Calculation of P-T Limits - Normal Operation

In the NRC staff's safety evaluation of WCAP-14040, Revision 1, included at the beginning of the approved version, WCAP-14040-NP-A, Revision 2, the staff concluded that the fracture mechanics calculation methods described in the topical report (used as the basis for the allowable pressures) conformed to Appendix G of 10 CFR Part 50 and SRP Section 5.3.2.

The NRC staff performed a confirmatory calculation of the P-T limits for PTN Units 3 and 4. The licensee identified two materials as limiting with respect to P-T curve development; the US forging with respect to axial flaws and the IS to LS circumferential weld with respect to circumferential flaws. The licensee did not indicate one material was more limiting than the other, so the NRC staff assumed the P-T curves provided bound both materials.

For the confirmatory calculation, the NRC staff used the methods of both the 1995 Edition through 1996 Addenda, and 2004 edition, of the ASME Code, Section XI, Appendix G. Starting with the 2000 edition of the ASME Code, Appendix G to Section XI incorporated the use of the K_{Ic} fracture toughness curve, rather than the K_{Ia} curve used in earlier editions, and additionally incorporated the use of different M_m membrane stress correction factors from Code Case N-588 applicable to circumferentially oriented flaws. The K_{Ic} curve provides higher fracture toughness for a given temperature differential from RT_{NDT} than does the K_{Ia} curve. The WCAP-14040-NP-A, Revision 2 methodology referenced by the licensee uses the more conservative K_{Ia} curve. Code Case N-588 allows the postulation of a circumferential rather than an axial flaw in a circumferential weld, and consequently specifies a different value of the membrane stress correction factor M_m. Therefore, the NRC staff calculated confirmatory P-T curves based on both the K_{Ic} and K_{IA} methodologies, and also used the M_m factors from the 2004 edition of Appendix G. Apart from the use of K_{Ic}, and the changes to the M_m factors for circumferential flaws, the methodologies allowed by the 1995 through 1996 edition and the 2004 edition are essentially the same.

The NRC staff used the simplified equations from ASME Code, Section XI, Appendix G, paragraph G-2214.3 to determine the maximum thermal stress intensity K_{It} resulting from inside or outside surface 1/4T flaws. WCAP-14040-NP-A, Revision 2 and the ASME Code, Section XI, Appendix G, contain more sophisticated equations allowing the determination of K_{It} from a cubic fit to the thermal stress distribution through the vessel wall.

In RAI CVIB-1.4 a, the staff requested the licensee to provide the K_{It} values used to generate the most limiting heatup and cooldown curves. By letter dated March 9, 2011, in response to RAI CVIB-1.4a, the licensee provided the K_{It} values used to generate the 100 °F/hr heatup and cooldown curves. Comparison of the licensee's K_{It} values to those calculated using the simplified ASME method showed that the licensee's K_{It} values were lower in magnitude in the early part of the transient (low temperatures for heatup or high temperatures for cooldown), but approach the simplified ASME values later in the transient. Since the licensee supplied the requested data, the NRC staff finds RAI CVIB-1.4a is resolved.

The NRC staff used Figure G-2214-1 and Figure G-2214-2 of the ASME Code, Section XI, Appendix G, to determine the temperature differential from the coolant to the crack tip location. In RAI CVIB-1.4b, the NRC staff requested the licensee to supply the values of this differential used in their calculation, and identify the method used by the licensee to determine the coolant to crack tip temperature differential, since more refined methods than the standard ASME method are sometimes used in this calculation. By letter dated March 9, 2011, in response to RAI CVIB-1.4b, the license supplied the temperature differentials for the 100 °F/hr heatup and cooldown, and indicated that the temperatures are calculated using the one-dimensional transient heat conduction equation that is contained in Section 2.6.1 of WCAP-14040-A, Revision 4. The licensee further indicated that a through-wall temperature distribution was calculated for each PTN Units 3 and 4 time step during each cooldown or heatup ramp of interest, and that these methods are incorporated into the OPERLIM computer code. Comparison of the licensee's temperature differential values for heatup to those generated using the simplified ASME method shows that the licensee's temperature differentials at the 1/4T and 3/4T locations are less than the ASME values in the lower temperature range, but greater than the ASME values at temperatures above 180 °F. For the 100 °F/hour cooldown, the temperature differential is greater, meaning the crack tip temperature is higher, by about 3-6 °F, over the temperature range of interest (310 °F down to 70 °F). Since the licensee supplied the requested data, the NRC staff finds that RAI CVIB-1.4b is resolved.

For the heatup limits for the IS to LS weld, the NRC staff used the method of the 2004 edition of the ASME Code, Section XI, Appendix G (which incorporates the provisions of ASME Code Case N-588). The methodologies cited by the licensee (WCAP-14040-NP-A, Revision 2 and the ASME Code, Appendix G, 1995 Edition through 1996 Addenda) do not allow the use of Code Case N-588, although the code case is allowed by WCAP-14040-NP-A, Revision 4. WCAP-15092, Revision 3, which provides the basis for the previous P-T limits for PTN Units 3 and 4 indicates the licensee's methodology uses the provisions of ASME Code Case N-588. In RAI CVIB-2.1, the NRC staff requested clarification on whether the licensee used the Code Case N-588 provisions, and clarification of which revision of WCAP-14040-A was used as the basis for the P-T limit methodology. The licensee's response by letter dated April 14, 2011,[19] indicates that the methodology of generating the P-T curves for PTN Units 3 and 4 is based on WCAP-14040-NP-A, Revision 2, as modified by the axial and circumferential flaw methodology contained in Code Case N-588. Along with the response, the licensee provided a revised markup of TS Basis 3/4.4.9 reflecting that Code Case N-588 is used. The NRC staff, therefore, finds that RAI CVIB-2.1 is resolved. For the confirmatory calculations, the NRC staff calculated the allowable P-T limits for both the US forging (assuming an axial flaw) and the IS to LS weld (assuming a circumferential flaw as allowed by Code Case N-588 and the 2004 edition of the ASME Code). The allowable pressure for a given temperature is based on the lowest calculated pressure for either material.

The NRC staff's confirmatory calculations showed that the if the provisions of the 2004 edition of the ASME Code, Section XI, Appendix G are used, including K_{Ic} and the modified M_m factors for the circumferentially oriented flaws, the licensee's P-T limits are more conservative than the ASME P-T limits, for all heatup and cooldown rates, and are therefore acceptable. When the NRC staff used the K_{Ia} fracture toughness curve with the ASME method, the P-T limits generated are more conservative than the licensee's P-T limits. The differences are significant

[19] ML1105A145

only for the 100 °F/hour heatup and 100 °F/hour cooldown curves. The differences can be attributed to the licensee's use of more refined methods to generate the K_{It} values and coolant-to-crack tip temperature differentials than the simplified ASME method of generating these parameters. However, since the K_{Ic} curve is incorporated into the ASME Code, Section XI editions (2000-2004) that have been incorporated by reference by the NRC into 10 CFR 50.55a, the NRC staff finds the licensee's P-T limits acceptable since they are more conservative than those that would be generated using an NRC-approved code edition, even though it is not the same year edition referenced by the licensee.

The NRC staff finds the licensee's proposed P-T limits to be acceptable based on: 1) the licensee used a methodology for generating P-T curves that an NRC staff SE concluded was consistent with the regulatory requirements of 10 CFR Part 50, Appendix G; and 2) the NRC staff's confirmatory calculations showed the licensee's P-T limits are more conservative than P-T limits generated using the methods of Appendix G to Section XI of an ASME Code edition, which has been approved by the NRC staff.

Core Critical P-T Limits

For normal operations with the core critical, 10 CFR Part 50 Appendix G requires that 40 °F be added to the temperature corresponding to the allowable pressure determined using the ASME Code, Section XI , Appendix G, for pressures both less than or greater than the preservice hydrostatic test pressure. The NRC staff verified that the core critical P-T limits provided on Figures 3.4-2 and 3.4-3 of the Technical Specifications, and Figures 2.1.2-1, and 2.1.2-2 of the LR, show the core critical P-T curves offset by 40 °F from the ASME Code, Section XI, Appendix G P-T curves.

Hydrotest Limits

The NRC staff performed a confirmatory calculation of the hydrotest limits using the method of the ASME Code, Section XI, Appendix G. The NRC staff's calculation confirmed the licensee's hydrotest limits.

Conclusion

USE

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the USE values for the RV beltline materials at EOL and for the plants. The NRC staff concludes that the licensee has adequately addressed the changes in neutron fluence and their impacts on the USE values for the plants. The NRC staff concludes that the PTN Units 3 and 4 RV beltline materials will continue to have acceptable USE values, as mandated by 10 CFR Part 50, Appendix G, or have been shown to have equivalent margins against ductile fracture via an analysis that used a methodology acceptable to the NRC staff, through the expiration of the current operating licenses for the facilities.

P-T Limits

Based on review of the changes to the material properties resulting from EPU, the NRC staff concludes that the licensee has appropriately accounted for the changes in neutron fluence due to EPU on the P-T limits. The NRC staff concludes that, based on confirmatory calculations and the use of a previously approved methodology for P-T limit development, that the licensee's P-T limits are at least as conservative as those determined using the methods of the ASME Code, Appendix G, and therefore meet the requirements of 10 CFR Part 50, Appendix G.

2.1.3 Pressurized Thermal Shock (PTS)

Regulatory Evaluation

The PTS evaluation provides a means for assessing the susceptibility of the RV beltline materials to PTS events to assure that adequate fracture toughness is provided to support reactor operation. PTS refers to an event or transient in pressurized water reactors (PWRs) causing severe overcooling (thermal shock) concurrent with or followed by significant pressure in the reactor vessel. The NRC 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 NRC 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 EOL 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.

10 CFR 50.61 provides a required methodology for calculating these RT_{PTS} values, which are based on the calculation methods in RG 1.99, Revision 2. For materials in the beltline region of the 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.

As noted above in Section 2.1.1, PTN Units 3 and 4 predate the GDC of 10 CFR Part 50, Appendix A. The licensee cited PTN GDC-34, which the NRC staff found to be equivalent to

GDC-31 and, therefore, is an acceptable regulatory criterion to be used by the licensee when evaluating RV integrity.

In LR Section 2.1.3.1, the licensee also cited PTN GDC-9, “Reactor Coolant Pressure Boundary,” which states, “The Reactor Coolant Pressure Boundary shall be designed, fabricated and constructed so as to have an exceedingly low probability of gross rupture of significant uncontrolled leakage throughout its design lifetime.” PTN GDC-9 is essentially equivalent to GDC-14 of 10 CFR Part 50, Appendix A. Therefore, the NRC staff finds PTN GDC-9 an acceptable regulatory criterion to be used by the licensee when evaluating RV integrity.

Licensee Evaluation

Section 2.1.3.2.2 of the LR discussed the input parameters, assumptions and acceptance criteria for the licensee’s PTS evaluation. LR Tables 2.1.3-1 and 2.1.3-2 provide the supporting data and the results of the licensee’s PTS evaluation. The licensee used the methodology of 10 CFR 50.61 to determine the RT_{PTS} values for the reactor vessel beltline materials at 60 years. The chemistry factors for the beltline materials were determined using Tables 1 and 2 of 10 CFR 50.61. When credible surveillance data was available, the licensee also determined the CF based on the surveillance data using Equation 5 of 10 CFR 50.61. The CFs used to calculate RT_{PTS} were determined using identical methods as were used to calculate the CFs for determining the ART used in the P-T limit development. Refer to Section 2.1.2 of this safety evaluation, in the subsection entitled, “Adjusted Reference Temperature and Identification of Limiting Material,” for a description of the methods for determining the CFs, and the results obtained, for the PTN Units 3 and 4 beltline materials. For those materials that have surveillance data, the licensee provided RT_{PTS} values based on the CFs from the 10 CFR 50.61 tables, and also based on the surveillance data.

The licensee stated in Section 2.1.3.2.2 of the LR that the neutron fluence for PTN Units 3 and 4 was determined using NRC-approved methodology that follows the guidance and meets the requirements of RG 1.190. The licensee referenced WCAP-16083-NP-A, Revision 0, “Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry,” as the NRC-approved fluence methodology. The NRC staff’s evaluation of the licensee’s neutron fluence analysis methodology is located in Section 2.1.1 of this safety evaluation.

NRC Technical Evaluation

The NRC staff performed a confirmatory calculation of the RT_{PTS} values for PTN Units 3 and 4, using the methodology of 10 CFR 50.61. As part of the confirmatory calculation, the NRC staff checked the copper, nickel and initial RT_{NDT}, values for the PTN Units 3 and 4 RVs provided by the licensee as input to the PTS evaluation, against the values for the same material heats from the RVID. For the weld materials, the NRC staff confirmed that the initial RT_{NDT} values and initial margin σ_i values for the weld materials are consistent with the values specified in BAW-2308, Revision 2-A, Table 9, since the NRC staff approved a plant-specific exemption allowing PTN to use that methodology to determine the initial RT_{NDT} of the weld materials. The NRC staff notes that there is no data in the RVID for the extended beltline materials, consisting of the inlet nozzles, outlet nozzles, and inlet/outlet nozzle welds. The initial RT_{NDT} values for the

inlet/outlet nozzle welds match values from BAW-2308, Revision 2-A for heat #299L44 and “other heats.”

Since the CFs based on surveillance data provided in LR Tables 2.1.3-1 and 2.1.3-2 in some cases differ from the values for the same materials in the RVID, the NRC staff requested the applicant provide the basis and the supporting calculation for the licensee’s CFs (letter dated March 9, 2011, RAI CVIB-1.4g). In accordance with 10 CFR 50.61, the results from the plant-specific surveillance program must be integrated into the RT_{PTS} estimate if the plant-specific surveillance data has been deemed credible, and since the licensee did not indicate whether the surveillance data were considered credible or not, the NRC staff requested the credibility evaluation of the surveillance data (RAI CVIB-1.4g). See Section 2.1.2 for the details of the NRC staff’s evaluation of the licensee’s response to RAI CVIB-1.4g. The NRC staff found the licensee’s determination of the CFs and credibility evaluation of the surveillance data to be acceptable. The licensee conservatively accounted for the surveillance data in the determination of the RT_{PTS} values. The CFs determined using the tables of 10 CFR 50.61 were larger and, therefore, more conservative than the CFs determined using surveillance data, resulting in higher RT_{PTS} values using the CFs from the tables. However, the RT_{PTS} values determined using the CFs from the tables meet the PTS screening criteria of 10 CFR 50.61, and are therefore acceptable.

In the confirmatory calculation, the NRC staff used the vessel inner diameter fluences provided by the licensee in Tables 2.1.1-1 and 2.1.1-2. Additionally, the NRC staff independently verified the licensee’s chemistry factor values by using the chemistry values supplied by the licensee in conjunction with the chemistry tables of 10 CFR 50.61. The NRC staff did not perform a confirmatory calculation of the chemistry factors determined using surveillance data, because the RT_{PTS} values determined using the tables are more conservative than those determined using the surveillance data. The NRC staff observed that all of the licensee’s values match those in RVID or BAW-2308, Revision 2-A, as applicable. The NRC staff confirmed that the RT_{PTS} values for all the beltline and extended beltline materials for PTN Units 3 and 4, are below the screening criteria of 270 °F for base materials and axial welds, and 300 °F for circumferential welds, and are therefore acceptable. The limiting material with respect to RT_{PTS} is the IS to LS shell circumferential weld for both units, with an RT_{PTS} of 247 °F at 48 EFPY.

Conclusion

Since the NRC staff confirmed that the licensee’s RT_{PTS} values meet the screening criteria of 10 CFR 50.61, the NRC staff finds the licensee’s PTS evaluation considering EPU is acceptable.

2.1.4 Reactor Vessel Internal and Core Support Materials

Regulatory Evaluation

The reactor internals and core supports (RVI) include structures, systems, and components (SSCs) that perform safety functions or whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the reactor coolant system (RCS)). The NRC staff’s review assessed the impact of the EPU on the margins of safety for

maintaining the structural integrity of the RV internal and core support components. The NRC's acceptance criteria for reactor internal and core support materials are based on 10 CFR Part 50. Appendix A, GDC-1, "Quality Standards and Records," and 10 CFR 50.55a, "Codes and standards," for inspecting and evaluating the structural integrity of reactor internal and core support components. 10 CFR 50.55a 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, Revision 0. For PWR design nuclear plants, Matrix 1 of RS-001, Revision 0, provides references to the NRC's approval of the recommended guidelines for RV internals in topical report WCAP-14577, Revision 1-A, "License Renewal Evaluation: Aging Management for Reactor Internals (March 2001)."[20]

In its regulatory evaluation of RVI, the licensee cited PTN GDC-1, "Quality Standards," which states:

> Those systems and components of reactor facilities which are essential to the prevention, or the mitigation of the consequences, of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required.

The NRC staff finds PTN GDC-1 is essentially equivalent to GDC-1 of 10 CFR 50, Appendix A, therefore, constitutes an acceptable regulatory criterion for the licensee to evaluate the quality standards applied to the RVI.

Licensee Evaluation

In LR Section 2.1.4.1, the licensee included their regulatory evaluation and a discussion of the current licensing basis of PTN Units 3 and 4 with respect to RVI components. The licensee's regulatory evaluation is consistent with the NRC staff's regulatory evaluation. In their discussion of the current licensing basis, the applicant noted that PTN Units 3 and 4 used the 1967 Atomic Energy Commission (AEC) Proposed GDC.

In LR Section 2.1.4.1, the licensee described the materials of construction of the RVI components as primarily Type 304 stainless steel, with some Alloy X-750 and Alloy 600 components. The licensee indicated the materials, fabrication techniques, and installed

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configurations are consistent with those described in WCAP-14577, Revision 1-A. Stresses are determined in accordance with the ASME Code, Section III, except for certain bolting materials including cold-worked Type 316 stainless steel and Alloy X-750, for which the ASME Code does not give allowable stresses. Essentially, the RVI were not designed strictly to ASME Code, Section III requirements, but the design is generally consistent with Section III with respect to stresses, fabrication techniques, and nondestructive testing requirements. The licensee described the major subsections and components of the RVI in this section.

LR Section 2.1.4.2 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 component materials during years 40-60, nor change the manner in which component aging will be managed by the aging management program credited in the topical report WCAP-14577, Revision 1-A and accepted by the NRC in the safety evaluation report.

The licensee listed the relevant degradation (aging) mechanisms for the RVI and core support materials that were considered potentially impacted by EPU and were evaluated to assess the effects of the EPU as:

A. Integrity of reactor vessel fuel cladding,
B. Intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC) of austenitic stainless steel,
C. Primary water stress corrosion cracking (PWSCC) of Alloy 600 and Alloy X-750 components
D. Irradiation-assisted stress corrosion cracking (IASCC) and void swelling of austenitic stainless steel,
E. Radiation induced excessive heating rates of RVI components
F. Thermal Growth of RVI Components
G. Thermal aging (embrittlement) of cast austenitic stainless steel (CASS)

In LR Section 2.1.4.2.2, the licensee described the service conditions of the reactor internals that will result from EPU. The water chemistry conditions are bounded by the current water chemistry conditions, with respect to boron, lithium, pH and impurities. The RV outlet (hot leg) maximum temperature will increase from 607.8 °F to 616.8 °F, while the RV upper head maximum temperature will increase from 599.3 °F to 608.8 °F. The maximum bottom-mounted instrumentation (BMI) penetration temperature will increase 2.6 °F from 546.6 °F to 549.2 °F. The licensee provided the projected neutron fluences at 21.15, 32, 50, and 60 effective full power years at the inner surface of the baffle plates.

In LR Section 2.1.4.2.3, the licensee evaluated the changes expected due to EPU for each aging mechanism listed above. The licensee identified no significant changes to the severity of the aging mechanisms due to 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 fuel-cladding corrosion effects, the licensee essentially indicated that post-EPU chemistry conditions will be bounded by the current chemistry conditions which are in

accordance with the latest Electric Power Research Institute (EPRI) Primary Water Chemistry Guidelines; therefore, no effect on fuel-cladding corrosion is expected.

Similarly, with respect to IGSCC and TGSCC, since these mechanisms are controlled through the chemistry control program, which minimizes contaminant concentrations that could cause these mechanisms, no change is expected since the chemistry control program will remain the same after EPU. Further, PTN follows the recommendations of RG 1.44, "Control of the Processing and Use of Stainless Steel," Revision 1 (March 2011), with respect to startup transient oxygen levels, which should help prevent both IGSCC and TGSCC.

With respect to PWSCC, the licensee has replaced Alloy X-750 guide tube support pins, which were susceptible to PWSCC, with PWSCC resistant Type 316 strain-hardened stainless steel. The clevis insert bolts are Alloy X-750. The clevis inserts and clevis insert lock keys are Alloy 600. The licensee's evaluation concluded the clevis inserts have low, compressive stresses, a relatively low temperature, and no history of degradation. Therefore, the effects of PWSCC on the clevis insert are not considered significant. The licensee also noted that WCAP-14577, Revision 1-A considered the potential for all forms SCC to be not significant for Alloy 600 and Alloy X-750 RVI components. The licensee also noted that since the chemistry program is not changing with EPU, there is no introduction of any of the PWSCC contributors such as stress, oxygen or halogens.

The licensee evaluated IASCC and irradiation embrittlement (IE) together even though they omitted IE from the list above. With respect to IASCC and IE, the licensee listed the following components as being most susceptible to the effects of crack growth due to IACC and loss of fracture toughness due to IE:

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

The licensee stated that IE of stainless steels can occur at fluences as low as $1x10^{21}$ n/cm^2 (E > 0.1 MeV) in the most susceptible stainless steels such as type 304, and that the change in mechanical properties is reduced at fluences above $2x10^{22}$ n/cm^2 (E > 0.1 MeV).

The licensee noted that although no instances of service-related RVI degradation has occurred that can be directly attributed to IE, the EOL fluence levels for some components is estimated at $1.504x10^{23}$ n/cm^2 (E > 0.1 MeV). Therefore, Turkey Point will continue to participate in the industry Materials Reliability Program efforts on RVI.

The licensee concluded the total amount and severity of void swelling in the RVI is expected to be minor through EOL based on current industry data. The licensee will continue to follow industry efforts to investigate swelling effects on the RVI.

For thermal aging embrittlement of CASS components, the licensee identified the susceptible components as the lower core support column bodies, lower support casting, BMI column

cruciforms, upper support column bases, UHI flow column bases, flow mixing devices, and lower and intermediate flanges. The licensee stated that the chemistry content and the service temperatures (354 °F -611 °F) at EPU conditions are not favorable to produce significant loss of toughness; therefore, the EPU is not expected to have any significant impact on the structural integrity of CASS.

With respect to radiation-induced heat generation (Gamma heating) and thermal growth, the licensee stated that the presence of radiation-induced heat generation rates in the RVI components, in conjunction with the reactor coolant fluid temperatures, result in thermal gradients within and between the components. The resultant material temperature gradients cause thermal stresses and thermal growth that must be considered in the design and analysis of various components. The licensee listed the baffle plates, former plates, core barrel, barrel-former bolts and baffle-former bolts, thermal shield, and the upper and lower core plates as the RVI components affected by gamma heating. However, the licensee stated that the results of the radiation-induced heat generation evaluations at the EPU conditions for PTN Units 3 and 4 showed there was margin between the current calculations and the design values.

The licensee concluded that there are no new degradation mechanisms for the RVI resulting from EPU, the program identified to manage these aging mechanisms are appropriate, and no changes are needed to the programs that manage these degradation mechanisms. With respect to the degradation assessment of the RVI conducted under license renewal, there are no changes to the materials included, component or system functions, system boundaries, and aging management programs identified. The licensee also concluded the RVI would continue to meet the regulatory requirements after EPU, GDC-1 and 10 CFR 50.55a.

NRC Technical Evaluation

Matrix 1 of the NRC review standard, RS-001 provides the NRC staff's basis for evaluating the potential for EPUs to induce these aging effects. In Table Matrix-1, the NRC staff states that, in addition to the SRP, guidance on the neutron irradiation-related threshold levels inducing IASCC in RV internal components are given in WCAP-14577. Topical report WCAP-14577, Revision 1-A establishes a threshold of $1 \text{ X } 10^{21}$ n/cm^2 (E > 1.0 MeV) for the initiation of IASCC, loss of fracture toughness, and/or void swelling in PWR RV internal components made from stainless steel (including cast austenitic stainless steels) or Alloy 600/82/182 materials. The licensee provided neutron fluences at both E > 1.0 MeV and E > 0.1 MeV for the inside surface of the baffle plates. The licensee did reference WCAP-14577, Revision 1-A as the basis for the threshold used to evaluate IASCC and IE, which the NRC staff finds acceptable.

Section 2.1.4.2.2 of the LR provides the 60-year peak fluence to the RVI as $1.504\text{x}10^{23}$ n/cm^2 (E > 0.1 MeV). However, the peak fluence pre-EPU was not provided for comparison. Additionally, for several of the aging mechanisms evaluated in Section 2.1.4, including IASCC, irradiation embrittlement, void swelling, and irradiation-enhanced stress relaxation, a threshold neutron fluence is identified in the LR. No additional components were identified in the LR as susceptible to these mechanisms due to EPU, compared to those components previously identified as susceptible to these mechanisms. It was not clear to the NRC staff how the screening for susceptibility to these mechanisms was accomplished. For example, a detailed "fluence map" for the RVI considering EPU, could be used to determine if new components exceed the fluence threshold as a result of EPU. For degradation mechanisms that depend on

applied stresses, such as stress corrosion cracking (SCC) and PWSCC, EPU could also affect the applied stresses. Temperature is also an important variable for many of the aging mechanisms to which RVI are susceptible. Therefore, in RAI CVIB-1.5a the NRC staff requested the licensee to describe the method of determining if additional RVI components become susceptible to the aging effects of 1) cracking due to SCC, IASCC, or PWSCC; 2) reduction of fracture toughness due to IE; 3) loss of material due to wear; 4) loss of mechanical closure integrity due to IASCC, IE, irradiation creep, or stress relaxation (SR); and 5) loss of preload due to SR, or dimensional change due to void swelling. RAI CVIB 1.5a also requested that the discussion address whether a detailed fluence and temperature map was used, and whether stresses in individual components were reevaluated. In RAI CVIB-1.5c, the NRC staff asked whether any additional RVI components were determined to be susceptible to any additional aging effects due to the mechanisms addressed in RAI CVIB 1.5a.

By letter dated March 9, 2011, RAI CVIB-1.5a, the licensee's responses for the various aging effects are as follows:

- With respect to cracking due to SCC, the licensee indicated that all RVI components had already been determined to be potentially susceptible to SCC, which is generally managed by the chemistry control program, thus the increase in temperature or stress due to EPU would not result in additional components becoming susceptible to SCC. Similarly, for PWSCC, the licensee indicated that all nickel-based alloy RVI components had already been identified in the license renewal application (LRA) as susceptible to PWSCC, and the minimal temperature increases due to EPU would not significantly increase the susceptibility of these components to PWSCC. The NRC staff agrees with the licensee's conclusion that the effect of the temperature change on SCC should be minimal, since the fluid temperature changes in the internals will increase only 2.6 °F to 9 °F. The NRC staff agrees that the effects on PWSCC should be minimal since the nickel alloy RVI components are generally located in the lower internals where the temperature increase is small (2.6 °F).

- With respect to both cracking due to IASCC and loss of fracture toughness due to IE, the licensee identified that based on a revised fluence map for EPU, two additional components (compared to those identified in the LRA) had been identified as being susceptible to cracking due to IASCC and loss of fracture toughness due to IE. For both aging mechanisms, the licensee cited a neutron fluence threshold of 1×10^{21} n/cm^2 (E > 0.1 MeV). For IASCC, the licensee additionally identified a stress threshold of 30 ksi. These thresholds are defined in WCAP-14577, Revision 1-A. The affected components are the upper core plate and the portions of the BMI columns. However, the licensee noted that the operating stresses in the BMI columns are well below the threshold for IASCC. The NRC staff compared the neutron fluence and stress thresholds used by the licensee to the latest thresholds defined by the industry in MRP-175, "Materials Reliability Program: PWR Internals Material Aging Degradation Mechanism, Screening and Threshold Values," and observes that the licensee is using more conservative thresholds.

- With respect to loss of material due to wear, the licensee indicated that the calculated increase in flow rates through the RVI resulting from EPU is less than 0.2 percent. Therefore, the licensee does not expect any increase in wear due to flow-induced vibration.

- With respect to loss of mechanical closure integrity due to IASCC, IE, irradiation creep, or SR, the licensee indicated that all bolting components were already identified in the LRA as susceptible to loss of mechanical closure integrity. The licensee stated that they did not expect the changes in stress in temperature would change the way bolting is managed during the period of extended operation.

- With respect to loss of preload, the licensee stated that besides core support bolting, the holddown spring would be the only other RVI component susceptible to loss of preload and it is identified as such in the LRA. The licensee further stated that Westinghouse evaluated the performance of the holddown spring with respect to the EPU, and determined that the reactor internals would remain seated and stable for the EPU conditions for the extended license period.

- With regard to void swelling, the licensee indicated that they are following the industry program, and that industry research has currently indicated a threshold fluence of 1.3×10^{22} n/cm^2 (E > 0.1 MeV). The licensee also indicated some RVI components will exceed this fluence value but that there is no indication of discernable effects attributable to swelling.

The NRC staff requested that the licensee discuss whether the projected amount of gamma heating of the RVI under EPU conditions is bounded by design projections of gamma heating, and if not, how the effects of gamma heating on the RVI under EPU conditions evaluated for acceptability (RAI CVIB-1.5b). In its response to RAI CVIB-1.5b (letter dated March 9, 2011), the licensee indicated that the projected amount of gamma heating of the RVI accounting for EPU is bounded by the design gamma heating. Therefore, there is no impact on the RVI with respect to gamma heating rates as a result of EPU conditions.

The NRC staff compared the licensee's evaluation of the RVI aging effects considering EPU to those aging effects identified as applicable to the RVI in the PTN Units 3 and 4 LRA. In the LRA for PTN Units 3 and 4, the aging mechanisms identified for the RVI are consistent with those identified for EPU with the exception of loss of material due to wear, loss of mechanical closure integrity, and loss of preload. In RAI CVIB-1.6, the NRC staff requested the licensee address this discrepancy in the aging effects evaluated between the LRA and the EPU submittal. The licensee's response for the three aging effects were similar to their responses for the same aging effects/mechanisms in RAI CVIB-1.5. The NRC staff considers that loss of material due to wear, loss of mechanical closure integrity, and loss of preload, have been adequately evaluated for EPU based on the responses to RAIs CVIB-1.5 and CVIB-1.6.

Based on the above, the NRC staff finds that the licensee has adequately evaluated the changes in the RVI components susceptible to the various aging effects, since the licensee used a fluence map of the RVI modeling EPU conditions, used an appropriately conservative neutron fluence threshold, and also quantified the change in temperature and coolant flowrate to the RVI. The NRC staff find's the licensee's conclusion that the increases in temperature due to EPU will have no significant effect on the RVI aging effects to be acceptable because the temperature change is relatively small, and there are no RVI components that were previously screened as not susceptible to the temperature-sensitive aging mechanism. The licensee has also performed component-specific evaluations of the effects of preload where necessary, such as for the RVI holddown spring. The NRC staff also agrees with the licensee's conclusion that

there should be no increased susceptibility to cracking due to SCC or PWSCC, due to the minimal changes in coolant temperatures.

With respect to adequacy of the licensee's existing aging management programs to manage the aging of the RVI, considering the components with additional aging mechanisms resulting from EPU, the NRC staff observes that Turkey Point committed in the LRA to submit its inspection program for RVI prior to the end of the current 40-year operating term for PTN Units 3 and 4 (See NUREG-1759, "Safety Evaluation Report related to the License Renewal of Turkey Point Nuclear Plant Units 3 & 4," Section 3.8.6 and Updated Final Safety Analysis Report (UFSAR), Supplement Section 16.1.6 (Appendix A of LRA)). NUREG-1759 also documents that PTN is participating in the EPRI Materials Reliability Program (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 submit an RVI inspection program conforming to the guidance of the standard industry program as did most of the later license renewal applicants. The topical report, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227, Revision 0),"[21] provides the industry's recommendations for plant-specific PWR RVI inspection and evaluation programs. However, by letter dated May 11, 2011,[22] the licensee provided a statement of their intent to submit an RVI inspection program conforming to the guidance of the NRC staff-approved version of MRP-227. Applicant/Licensee Action Item 1 of the final safety evaluation of MRP-227 requires that licensees perform an evaluation of its plant's operating history (including the effects of any power uprate) demonstrating the applicability of MRP-227, Revision 0 to the facility. Therefore, conformance with Applicant/Licensee Action Item 1 should ensure the changes in fluence due to EPU are adequately considered when assessing the adequacy of the generic guidance in MRP-227, or whether plant-specific modifications to the inspections are required. Finally, when the plant-specific RVI inspection program for PTN Units 3 and 4 is submitted to the NRC staff for review, the staff will review the program to ensure that it adequately manages all the applicable aging effects for all RVI components, including the two components affected by additional aging mechanisms due to EPU.

Note 1 to Matrix 1 of RS-001, states that for thermal and neutron embrittlement of cast 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 provide a plant-specific program, and has stated their program will be consistent with the industry generic RVI inspection program guidance, which takes into account the industry findings on void swelling, SCC, and thermal and neutron embrittlement of CASS and, therefore, the NRC staff finds that the recommendation in Note 1 to Matrix 1 of RS-001 is met.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RV internal and core support materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to

[21] ML090160204
[22] ML11152A068

address the effects of changes in operating temperature and neutron fluence on the integrity of these components.

The NRC staff finds that the licensee has appropriately evaluated the potential for age related degradation of the RVI because they considered the changes in neutron fluence, temperature, and water chemistry in their evaluation. The NRC staff agrees with the applicants conclusion that the RVI as a whole will experience no new aging mechanisms or effects due to 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).

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

2.1.5 Reactor Coolant Pressure Boundary Materials

Regulatory Evaluation

The reactor coolant pressure boundary (RCPB) defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff's review of the RCPB materials covered their specification, 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 structures, systems, and components (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, "Environmental and Dynamic Effects Design Bases," 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.

The licensee has noted that the GDC used during licensing PTN predate those provided today in 10 CFR 50, Appendix A. The PTN GDCs were developed based on the 1967 Atomic Energy Commission Proposed GDC and are addressed in various sections of PTN's UFSAR.

1. GDC-1 is covered in PTN GDC-1, Quality Standards, which states:

   > Those systems and components of reactor facilities which are essential to the prevention, or the mitigation of the consequences, of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required.

   This requirement is further covered in UFSAR Sections 4.1.2 and 4.1.7.

2. PTN has no plant-specific GDC requirement that is analogous to GDC-4 , but such requirements are addressed under PTN's environmental qualification program.

3. GDC-14 is covered in PTN GDC-34, "Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention," which states:

   > The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failure. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation, and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes.

   This requirement is further covered in UFSAR, Sections 4.1.3 and 4.1.7, and Technical Specification 3/4.4.9 and its bases documentation, "Pressure/Temperature Limits", which describes that all components in the reactor coolant system (RCS) are designed to withstand the effects of cyclic loads due to system temperature and pressure changes.

4. The requirements of 10 CFR Part 50, Appendix G are in UFSAR Sections 16.3.1.3, 4.1.3, 4.3.3, and 16.3.1.2. In addition, PTN's reactor vessel and associated RCPB component materials were evaluated for the continued acceptability and applicability for the plant license renewal. The results of the review are documented in both the UFSAR, Section 16 on aging management and in NUREG-1759.

Specific review criteria are contained in the 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 97-01, Information Notice 00-17, Bulletin (BL) 01-01, BL 02-01, and BL 02-02. Additional review guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute, dated May 19, 2000.

NRC Technical Evaluation

The licensee indicated that the RCPB defines the boundary of systems and components containing the high-pressure fluids circulated in the reactor. The PTN evaluation of RCPB materials covered their specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. No materials of construction were changed as a result of the EPU.

General Corrosion/Wastage of Carbon Steel Components

The licensee stated that EPU chemistry limits will continue to be consistent with the recommended EPRI guidelines, which are developed based on operating plant experience and are designed to prevent corrosion degradation issues with RCPB materials. The chemistry changes do not involve introduction of any of the contributors (stress, oxygen or halogen) to material degradation. An increase in temperature will affect the corrosion rate; however, the percent change in absolute temperature is so small as to not be a significant issue.

As part of its license renewal application, PTN has expanded its Boric Acid Corrosion Control program scope to become consistent with NRC's NUREG-1801, "Generic Aging Lessons Learned Report," (GALL Report), incorporated lessons learned from the Davis-Besse Nuclear Power Station, and addressed the NRC's generic communications. The NRC concluded that PTN demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the Current Licensing Bases for the period of extended operation as required by 10 CFR 54.21(a)(3) (Agencywide Documents Access and Management System (ADAMS) Accession No. ML003749525). Temperature increase will affect the rate of boric acid deposit corrosion; however, the absolute temperature change is minimal and should not lead to an increase in the rate of corrosion.

The staff notes that the reactor coolant chemistry limits will minimize the potential increase in general corrosion and wastage of carbon steel components under EPU conditions. Should corrosion occur, the staff notes that the boric acid corrosion control program will monitor and control corrosion caused by external wet boric acid deposits. Therefore, the staff finds that PTN has satisfactorily addressed the EPU conditions in terms of potential corrosion and wastage of carbon steel components.

Austenitic Stainless Steels

The two degradation mechanisms that are applicable in the pressure boundary austenitic stainless steel materials in the RCPB are intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC). Sensitized microstructure, susceptible

materials, and the presence of oxygen are required for the occurrence of IGSCC, while the introduction of halogens such as chlorides and the presence of oxygen are prerequisites for the occurrence of TGSCC. The chemistry changes resulting from the EPU do not involve introduction of any of these contributors so that no effect on material degradation is expected in the stainless steel components as a result of the power uprate.

The licensee requires that the reactor coolant be rigorously controlled, particularly with regards to oxygen, chlorides and other halogens. The RCS primary water chemistry is controlled, particularly with regards to oxygen, chlorides and other halogens, in accordance with the requirements of the PTN chemistry control program, which is consistent with EPRI recommended guidelines. Experience with operating plants suggest that increasing initial lithium (Li) concentrations of up to 3.5 parts per million (ppm) while maintaining pH values between 6.9 and 7.4 has not produced any undesirable material integrity issues. PTN plans to coordinate their lithium/boron program such that the pH value is maintained between 6.9 and 7.4 while the Li levels are maintained less than 3.5 ± 5 percent ppm for the 18-month cycle.

The staff finds that EPU will not change the RCS chemistry significantly and that the change in material degradation of austenitic stainless steel components will be insignificant. In addition, the licensee has a chemistry control program to minimize the oxygen and halogens and maintaining proper pH values. The staff finds that the licensee has addressed the impact of EPU on the potential degradation of austenitic stainless steel components satisfactorily.

Alloy 600 Management Program

The licensee stated that they have recently adopted a comprehensive Alloy 600 management program that identifies Alloy 600/82/182 locations, evaluates and prioritizes the locations based on PWSCC susceptibility and develops mitigation and repair options. The impact of EPU on Alloy 600/82/182 components is discussed below.

Effect of EPU on the PWSCC Susceptibility of Alloy 600/82/182 Components at PTN

At PTN, the Unit 3 and Unit 4 reactor vessel closure heads with Alloy 600/82/182 penetrations were replaced with new heads with Alloy 690/52/152 penetrations in 2004 and 2005, respectively. Laboratory and field experience to date suggests that Alloy 690 and its associated 52/152 welds are more resistant to PWSCC than Alloy 600/82/182 material. The licensee stated that even though an increase of 9.5 °F in the closure head service temperature, a 9.0 °F increase in the hot leg temperature and a 2.6 °F increase in the BMI service temperature are predicted due to the EPU at PTN, the proposed uprating is not expected to have significant impact on the PWSCC degradation of the Alloy 690/52/152 RVCH penetrations or the Alloy 600/82/182 BMIs and clevis inserts.

The NRC notes that pursuant to 10 CFR 50.55a(g)(6)(ii)(D), the current inspection requirements for the PTN replacement head with Alloy 690 penetrations and associated weld materials will require the following:

- An initial bare metal visual examination shall be performed before or during the third refueling outage after installations of the replacement head, or within 5 calendar years of replacement, whichever occurs first. Repeat bare metal visual examinations shall be

performed at least every third refueling outage or every 5 calendar years, whichever occurs first.

- All plants having replacement head with Alloy 690 nozzles attached with Alloy 52/152 J-groove welds shall perform an in-service volumetric and/or surface examination every 10 calendar years.

The NRC inspection requirements for the replacement upper heads are not affected by a change in operating temperature, therefore continued implementation under the current requirements will maintain reasonable assurance of structural integrity. PTN performed bare metal visual inspections of the Unit 3 replacement RVCH during the spring 2009 outage and performed bare metal visual inspections on the Unit 4 RVCH during the fall 2009 outage. PTN achieved 100 percent coverage for both units, with no evidence of accumulated boric acid on any of the reactor vessel closure head penetrations or on the heads themselves.

NRC notes that current inspection requirements for the PTN bottom mounted nozzles would require a bare metal visual inspection every other refueling outage. A 2.6 °F change in temperature would slightly increase the susceptibility of the PTN BMIs to PWSCC initiation. However, this temperature effect is not sufficient to warrant a change in the current inspection program, which the NRC continues to find provides reasonable assurance of structural integrity of the reactor vessel at PTN.

Clevis inserts and the steam generator divider plate welds are not part of the reactor coolant pressure boundary. However, as components in the reactor coolant system, degradation of these items is monitored through the reactor vessel internals and steam generator programs. While the change in reactor coolant temperature will slightly increase the susceptibility to cracking of these components, the management programs in the GALL Report are not temperature sensitive. A change in temperature does not require a change in inspection frequency and the licensee's current inspection programs are adequate to ensure safe operation of the reactor coolant system.

The licensee stated that Alloy 600 and Alloy 82/182 weld deposits are present in the PTN RCS at the following locations:

- Bottom-mounted instrumentation nozzles.
- Reactor vessel clevis inserts and lock keys.
- Steam generator channel divider plate welds.

The staff notes that PWR operating experience has shown that PWSCC is a potential degradation mechanism in nickel-based Alloy 600/82/182 components. The NRC has set forth inspection requirements in 10 CFR 50.55a(g)(6)(ii)(D) and (E) to monitor the structural integrity of Alloy 600/82/182 components. In the proposed rule for 10 CFR 50.55a published on May 4, 2010 (75 FR 24324), the NRC adopted ASME Code Case N-770 with conditions. Code Case N-770 provides requirements for the inspection of Alloy 600/82/182. Temperature changes of the magnitude in the EPU will not change the inspection requirements of the Code Case. The staff finds that the licensee has implemented an Alloy 600 management program that will identify Alloy 600/82/182 components, evaluates PWSCC susceptibility, and develop mitigation and repair options. The staff finds that the licensee's Alloy 600 program will monitor degradation under the EPU conditions effectively.

Thermal Aging of Cast Austenitic Stainless Steels (CASS)

The licensee stated that at PTN a small increase (9.0 °F) in the hot leg temperature was assessed due to the EPU and that the effect of this change in the service temperature on the thermal aging is considered. The topical report WCAP-14575-A, "License Renewal Evaluation: Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components," indicates that thermal aging causes reduction in fracture toughness of the CASS component material and, hence, reduction in the critical flaw size that could lead to component failure. The impacted RCPB CASS components include RCS piping elbows, valve bodies, RCP pump casing and closure flanges. The evaluation documented in WCAP-15354, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Turkey Point Units 3 and 4 Nuclear Power Plants for the 60-Year Plant Life," demonstrated that a significant margin exists between detected flaw size and flaw instability. The 9.0 °F increase in the hot leg is within the evaluation of WCAP-15354. Furthermore, aging management for CASS in the GALL Report is not temperature dependent and, accordingly, an aging management program to manage the effect for the RCS piping components is not required beyond the examinations required by ASME Section XI.

Westinghouse performed an evaluation of the Code Case N-481 integrity analysis to identify if it is acceptable for the extended operating period. The results of the evaluation concluded that the previous integrity analysis conclusions documented in WCAP-13045, "Compliance to ASME Code Case N-481 of the Primary Loop Pump Casings of Westinghouse Type Nuclear Steam Supply Systems," and WCAP-15355, "A Demonstration of Applicability of ASME Code Case N-481 to the Primary Loop Pump Casings of the Turkey Point Units 3 and 4," for the PTN Units 3 and 4 RCP casings remain valid for the 60-year licensed operating period. The 9.0 °F increase in the hot leg is within the evaluations of WCAP-13045 and WCAP-15355 and an aging management program beyond the examinations required in Section XI is not required to manage the thermal embrittlement effect for the RCP casings.

The topical report, WCAP-14575-A, proposed programs to manage the effects of thermal aging of CASS components during the period of extended operation. The NRC assessed these programs and the safety evaluation (Section 3.3.3) states that valve bodies are adequately covered by existing inspection requirements in Section XI of the ASME Code and that screening for susceptibility to thermal aging is not required during the period of extended operation because the potential reduction in fracture toughness of these components should not have a significant impact on critical flaw size. The licensee believes that thermal aging as a result of the EPU is not expected to significantly affect cast components, including pumps, piping and valves at PTN.

The staff does not have concerns regarding the licensee's use of Code Case N-481. However, ASME has annulled Code Case N-481 and the RG 1.147, "Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1," Revision 16, (October 2010), Table 3 has documented such fact. The requirements of Code Case N-481 have been incorporated into the ASME Code, Section XI. In terms of EPU impact, the staff does not believe an increase of 9.0 °F in the hot leg temperature would significantly affect the thermal aging of CASS. The licensee has used the saturated (lowest) fracture toughness of CASS in its leak before break evaluation to demonstrate the acceptability of the CASS components. In addition, the licensee

will inspect the CASS components periodically to monitor potential thermal aging effect of CASS. Therefore, the staff finds that the licensee's assessment of the impact of EPU conditions on CASS components acceptable.

Environmentally Assisted Fatigue

The licensee states that environmentally assisted fatigue cumulative usage factor (CUF) for RCS components that were evaluated during its license renewal application were shown to be less than 1.0 for EPU conditions, with the exception of the RCS hot leg pressurizer surge line nozzle which assumed the presence of conservative stratification loads. The licensee states that this result is consistent with the CUF evaluation performed for the license renewal application for which PTN has committed to inspect all welds in the surge lines of Units 3 and 4. All welds at time of submittal had been inspected except one, which was completed during the 2010 fall outage and found acceptable. Results of all inspections for the surge line welds show no effects of the stratification loads.

The staff finds that the licensee has considered EPU conditions in the environmentally assisted fatigue cumulative usage factor calculations for RCS components as part of its license renewal application. The staff finds that the licensee has demonstrated that under the EPU conditions, the environmentally-assisted fatigue usage factors of the RCS components satisfy the ASME Code, Section III allowable except for the pressurizer surge line. For the pressurizer surge line, the licensee has inspected all the welds in the pressurizer surge line to confirm its structural integrity. The staff notes that the structural integrity of the pressurizer surge line will be monitored continuously as part of the inservice inspection program. Therefore, the staff finds that the licensee's assessment of the impact of the EPU on the environmentally-assisted fatigue acceptable.

License Renewal Impact Evaluation

In the license renewal application, the licensee identified the RCS pressure boundary materials of construction and likely aging effects along with effective aging management programs. The NRC summarized its evaluation in NUREG-1759, the safety evaluation report related to the license renewal of PTN Units 3 and 4. NRC staff concluded that the aging effects associated with the RCS components will be adequately managed so that the intended functions will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff finds that the small increase in RCS temperature caused by the EPU does not change the aging effects identified in the evaluations of the effectiveness of the aging management programs.

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 finds that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of the RCPB materials.

The staff finds that while the increase in temperature and elevated chemistry during EPU conditions at PTN has a minor effect on RCS component materials, no new failure mechanisms are introduced due to the EPU that challenge RCPB materials. Therefore, the staff concludes that the licensee's activities to maintain chemistry control and an effective inspection program that were accepted by the staff under NUREG-1759 provide an acceptable level of quality and safety. The staff finds that the above listed materials will not be adversely affected in a significant manner due to the EPU.

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. The 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 structures, systems, and components (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 general design criteria (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. NRC staff guidance for LBB analyses is contained in SRP Section 3.6.3 and NUREG-1061, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee," Volume 3 (November 1984). The 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 1.0 on loads.

The staff notes that PTN was designed and constructed based on the 1967 Atomic Energy Commission (AEC) Proposed GDCs. However, the requirements are addressed in various sections of the UFSAR, PTN GDC-40 and PTN GDC-4. The NRC's safety evaluation of the licensee's LBB analysis for RCS piping for plant licensing renewal is documented in Section 4.7.3 of NUREG-1759. As indicated in the safety evaluation, the aging effects associated with thermal aging of the primary loop piping components and fatigue crack growth were addressed and the LBB analysis revised to cover the time period of license renewal.

NRC Technical Evaluation

In section 2.1.6.2 of its EPU 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. It was also determined by the NRC in Generic Letter 84-04, “Asymmetric LOCA Loads,” that PTN need not consider asymmetric blow down loads resulting from double-ended pipe breaks in primary loop piping in their design basis. The licensee also stated a plant specific LBB analysis for the PTN Units 3 and 4 primary loop piping was performed by Westinghouse in 1994 and documented in WCAP-14237, which was approved by the NRC. The licensee revised its LBB analysis in 2000 as part of the license renewal application and the results are documented in WCAP-15354. The conclusions of the original LBB remained unchanged and also valid for the 60-year operating period.

To support the EPU at PTN, the licensee evaluated the current LBB analyses to address EPU conditions. In the license renewal application, the revised LBB analysis in WCAP-15354 addressed the extended period of operation utilizing criteria consistent with the requirement of NUREG-1061, Volume 3, and the draft SRP Section 3.6.3. The revised LBB analysis bounds EPU conditions. The staff determined that EPU conditions have minimal impact to the LBB results and margins. The conclusions reached for LBB for License Renewal are still applicable and valid for EPU conditions and for the period of extended operation. Therefore, the NRC’s safety evaluations regarding the LBB application at the PTN nuclear plant as documented in NUREG-1759 remain valid for EPU. PTN does not have any butt welds containing Alloy 600/82/182 in the piping covered by the LBB analysis. Therefore, PWSCC susceptibility of Alloy 600/82/182 does not affect the LBB analysis under the EPU conditions.

Conclusion

The NRC staff has reviewed the licensee’s evaluation of the effects of the proposed EPU on the LBB analysis for the plant and concludes that the licensee has adequately addressed changes in primary system pressure and temperature and their effects on the LBB analyses. The 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 piping 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 System (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 Staff’s review covered protective coating systems used inside the containment for their suitability for and stability under design basis loss-of-coolant accident 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, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing

Plants," which states quality assurance requirements for the design, fabrication, and construction of safety-related SSCs and (2) RG 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," Revision 1, for guidance on application and performance monitoring of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2.

NRC Technical Evaluation

The licensee stated that PTN has no specific commitments regarding compliance with RG 1.54, Revision 1. Alternatively, PTN treats coatings as a special process subject to the requirements of 10 CFR Part 50, Appendix B, Criterion IX, "Control of Special Processes." The coating program is controlled in accordance with American National Standards Institute (ANSI) N45.2 requirements, which addresses both new coatings and ongoing maintenance activities.

Florida Power & Light Company's (FPL's) Service Level 1 coating specification on protective coatings for applications inside the reactor containment building provides the technical requirements for protective coating work performed inside the PTN Unit 3 and 4 containment buildings. The licensee stated that the coating specification provides the necessary technical information and controls to assure that new coatings are of a high quality, reliable, meet applicable regulatory requirements, qualified to prevent transport of paint debris to the emergency core cooling system (ECCS) sump under post-LOCA conditions, provide corrosion control, and provide a suitable surface which will facilitate radioactive decontamination. The licensee further stated that the specification covers the procurement, storage, removal of existing coatings, surface preparation, application, inspection, applicator's certification, quality assurance documentation, condition assessment, and other related coating activities. The codes and standards used to develop the current specification are ANSI N101.2, ANSI N101.4, ANSI N45.2.2, ANSI N45.2.6, and 10 CFR 50, Appendix B. The licensee also stated that adequate assurance that the implementation of the applicable requirements for procurement, application, inspection, and maintenance is provided by procedures and programmatic controls approved under the FPL quality assurance program.

For the purposes of this review, the staff evaluated the results of the design basis accident (DBA) qualification testing of the Service Level I coatings used in containment to ensure that the DBA testing bound the anticipated conditions inside containment following a DBA-LOCA at EPU conditions. In a response to a request for additional information (RAI) dated March 16, 2011, as revised by letter dated July 22, 2011, the licensee provided a list of each coating system's DBA testing parameters for the staff to review. Under all conditions of temperature, pressure and irradiation the staff verified that the DBA test conditions bound the expected post-LOCA EPU conditions of 281.8 °F, 53.9 pounds per square inch gauge (psig) and 2.4×10^8 Rads, respectively. Additionally, the staff verified all but one coating system was tested at a pH level that bound the expected maximum post-LOCA EPU pH of 7.4 – 8.0. The additional coating, Carboline 1340 Clear, was tested in a water chemistry consisting of demineralized water. The staff finds this acceptable because the difference in pH between 7.4 – 8.0 and that of demineralized water, approximately 7.0, is negligible and will not negatively impact the ability of the coating system to perform its intended function.

In response to recent operating experience at PTN Unit 3 and 4, documented in licensee event report (LER) 2010-005-00,[23] the staff generated an RAI to determine which coating system would be used to replace the existing coating system in the reactor pit area. In the response dated March 16, 2011,[24] the licensee stated that Carboguard 890N, which is a cycloaliphatic amine nuclear grade DBA tested self priming epoxy mastic, designed for both periodic immersion and sever chemical environments, will be used to replace the current coating system utilized on the containment liner plate. The licensee provided the results of the DBA testing performed on the Carboguard 890N coating system and the staff finds that the DBA testing bounds the conditions expected during a post-LOCA at EPU conditions. The licensee also stated that additional testing was performed, beyond what was required for DBA testing. These tests consisted of immersion of the coating system in boric acid for 120 hours and a salt fog exposure for 2000 hours. The licensee further stated that the results of the testing performed on one and two coats of the Carboguard 890N bound the chemical environment that is anticipated in the reactor pit elevation. Additionally, the licensee discussed programmatic changes in the containment coatings program and the ASME Code, Section XI, Subsection IWE/IWL program to include the lower reactor cavity pit area in walkdowns conducted by examiners. Similarly, the licensee stated that the boric acid corrosion control program was revised to provide specific guidance for ensuring leakage of borated water from the upper reactor cavity is identified. The staff finds these additional tests and programmatic enhancements acceptable for ensuring that the replacement coating system will perform its intended function once applied.

The staff has reviewed the licensee’s evaluation and has confirmed that the applicable regulatory guidance was followed. The staff concurs that the coatings will not be adversely impacted by the EPU and that temperature, pressure, and radiation limits under power uprate conditions continue to be bounded by the conditions to which the coatings were qualified

Conclusion

The 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 design basis loss-of-coolant accident and their effects on the protective coatings. The staff further concludes that the licensee has demonstrated that the current, and replacement, protective coatings will continue to be acceptable following implementation of the proposed EPU and will meet the requirements of 10 CFR Part 50, Appendix B. Therefore, the 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

[23] ML103620112
[24] ML110770020

even small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on flow velocity, component geometry, fluid temperature, steam quality, oxygen content, and pH. During plant operation, it is not normally possible to maintain all of these parameters in a regime that minimizes FAC; therefore, loss of material by FAC can occur. The 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 states that their FAC program is based on NUREG-1344, "Erosion/Corrosion-Induced Pipe Wall Thinning in US Nuclear Power Plants," April 1, 1989, Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," May 2, 1989 (ADAMS Accession No. ML031200731), and the guidelines in the Electric Power Research Institute's (EPRI) Report NSAC-202L-R2, Recommendation for an Effective Flow-accelerated Corrosion Program, May 2006. The FAC program consists of predicting material loss by the use of the CHECWORKS computer code, visual inspection, and volumetric examination of the affected components. The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

NRC Technical Evaluation

The licensee stated that the PTN FAC program manages the aging effect of loss of material due to flow-accelerated corrosion. This aging management program predicts, detects, monitors, and mitigates FAC wear in high energy carbon steel piping systems containing single phase or two phase fluids. The licensee further stated that the corporate FAC program is based on the guidelines in EPRI NP 3944, "Erosion/Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines," and Nuclear Utility Management and Resource Council (NUMARC) guidelines for a long-term flow accelerated corrosion monitoring program, and industry experience. The PTN FAC program satisfies FPL's response to the NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning" and is continually being upgraded utilizing the guidelines of NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program." The PTN FAC program includes (a) analysis using the EPRI CHECWORKS computer code to determine critical locations, (b) baseline inspections to determine the extent of thinning at these locations, (c) follow-up inspections to confirm the predictions, and (d) repairing or replacing components, as necessary.

During each outage, the components selected for inspection are determined by utilizing the CHECWORKS predictive model to evaluate piping systems in order to focus inspection resources on the locations most susceptible to degradation. This plant-specific CHECWORKS model provides quantitative estimates of FAC rates and times to reach the minimum wall thickness. Inputs to the model include plant operating parameters, component material and design features, and inspection results. Additionally, the PTN FAC program utilizes program history, the engineering judgment of the plant engineers, and industry experience to determine inspection sites.

The licensee stated that components are inspected for FAC wear using ultrasonic techniques (UT), radiography techniques, or by visual inspection, and that the volumetric examination method is the primary method to investigate whether or not wear is present. The licensee stated that when a component is opened for maintenance activities, the visual examination method may be used. Small bore piping system analysis is addressed on a case-by-case basis

using the experience and engineering judgment of FPL system engineers, operating personnel, mechanical maintenance, and the FAC engineer. The licensee additionally stated, based on review of the EPU heat balance, no additional systems or portions of systems are required to be monitored at EPU conditions.

The licensee stated in its October 21, 2010, application that the PTN CHECWORKS predictive model was updated to reflect the plant at EPU temperatures, pressures, and velocities. The resulting model detailed EPU wear rates, and the changes due to uprate conditions that would direct future plant inspections. Additionally, the licensee provided tables comparing the wear rate of FAC susceptible components before and after implementing the EPU. The tables also reported the expected service life of selected component as predicted by the CHECWORKS program. The maximum corrosion rate increase predicted was 37.66 prcent, located in the extraction steam piping lines leading up to the 6th feedwater heaters, as a result of a decrease in steam quality due to the EPU. The staff finds the corrosion rate increases reasonable for the corresponding changes in operating conditions. Additionally, in the response to an RAI, dated March 16, 2011, the licensee provided a sample list of components for which wall thinning was predicted and measured by UT, or another approved method, to provide a comparison between actual wall thickness of a component and the predicted wall thickness by the CHECWORKS program. The staff finds that the CHECWORKS program provides adequate conservatism between predicted wall thickness and measured wall thickness, and the staff has reasonable assurance that the program will continue to be an acceptable predictive model after the implementation of the EPU. The licensee stated that the requirements, methods, and criteria of the existing FAC program will continue to be implemented following the EPU and that no changes to the existing elements will be required as a result of the EPU.

The staff has reviewed the licensee's evaluation and has determined that the applicable regulatory guidance was followed. The licensee has demonstrated that the FAC program is adequate for managing the potential effects on the piping components susceptible to FAC. The staff concurs that the FAC program is adequate in predicting the rate of material loss.

Conclusion

The 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. Additionally, the 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 staff finds the proposed EPU acceptable with respect to FAC.

2.1.9 Steam Generator Program

Regulatory Evaluation

Steam generator (SG) tubes constitute a significant part of the reactor coolant pressure boundary (RCPB). The staff reviewed the effects of changes in differential pressure, temperature, and flow rates resulting from the proposed EPU on plugging limits and potential degradation mechanisms (e.g., flow-induced vibration). The NRC's acceptance criteria for the SG program 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, "Steam Generator Program," Revision 2, and other guidance provided in Matrix 1 of RS-001, "Review Standard for Extended Power Uprates." Additional review guidance is contained in technical specification (TS) 6.8.4.j for SG program, Regulatory Guide (RG) 1.121, "Bases for Plugging Degraded PWR [Pressurized Water Reactor] Steam Generator Tubes," Generic Letter (GL) 95-03, "Circumferential Cracking of Steam Generator Tubes," and Bulletin 88-02, "Rapidly Propagating Fatigue Cracks in Steam Generator Tubes."

NRC Technical Evaluation

Turkey Point Nuclear Plant (PTN) Units 3 and 4 each have 3 Westinghouse Model 44F SGs. Each SG has 3,214 thermally treated Alloy 600 tubes. The SGs have tubes that were hydraulically expanded into the tubesheet. The tubes are supported by Type 405 stainless steel tube support plates with broached quatrefoil holes. The PTN Unit 3 and Unit 4 SGs were placed into operation in 1982 and 1983, respectively. The licensee stated that PTN has an established SG program that is implemented to ensure that SG tube integrity is maintained per the requirements of TS 6.8.4.j. The licensee utilizes structural and leakage performance criteria defined in TS 6.8.4.j.b in maintaining SG tube safe conditions.

The licensee stated that an analysis in accordance with RG 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing," as it relates to PWRs, was performed. The licensee reported that the following areas were included in the analysis in order to evaluate the potential adverse effects of acoustic resonances and flow-induced vibrations on the SG steam dryer components: 1) operating experience, 2) comparative evaluations, and 3) analytical results.

The applicant determined that plant operation of the PTN Units 3 and 4 SGs, with the two-tiered steam dryer equipment shows no indication of flow or acoustical type vibration concerns. In addition, the licensee performed a basic finite element analysis on the SG steam dryer bank assemblies and determined that the SGs have high natural frequencies based on their rigid structure and loadings. As a result, the licensee stated that the stresses in the SG dryer structure and attachment welds are well below the fatigue endurance limit of their respective materials.

The licensee evaluated the effects of elevated temperature on SG tube integrity. The licensee reported that the maximum EPU T_{hot} (616.8 °F) is an increase of 14.9 °F from PTN Units 3 and 4 current operating conditions. The licensee indicated that this increase in T_{hot} may result in an 82 percent potential increase in the corrosion rate initiation and propagation for primary water stress-corrosion cracking (PWSCC) for susceptible locations and a 48 percent increase in initiation for outside diameter stress-corrosion cracking (ODSCC). The licensee indicated that the SG program implemented in accordance with PTN Units 3 and 4 technical specifications will be able to address the potential increase in PWSCC and ODSCC initiation and propagation rates.

The license reported that an analysis was performed to evaluate the conservatism of the differential pressure limits. The licensee stated that the analysis evaluated the increase in the primary-to-secondary side differential pressure to 1700 pounds per square inch (psi) from 1549 psi. The analysis was performed for high T_{avg} and low T_{avg} conditions at 10 percent tube

plugging levels. In addition, an analysis was performed to evaluate upset conditions due to transients at 1870 psi (110 percent of 1700). The licensee indicated that the results of the analysis show that the EPU primary-to-secondary side differential pressure limits of 1700 psi for normal transients and 1870 psi for upset transients will continue to ensure that tube integrity will be maintained.

Since PTN has Model 44F SGs with thermally treated Alloy 600 tube material, the licensee stated that the SG tubes have not demonstrated susceptibility to circumferential cracking; this is further discussed in its response to GL 95-03. The license also stated that the SGs were fabricated with 405 stainless steel tube support plates and therefore are not subject to the issues raised in the Bulletin 88-02; this is fully addressed in its response letter to Bulletin 88-02.

The staff has reviewed the licensee's evaluation and calculation results found in the amendment request. The staff finds that the licensee has appropriately identified the effects of temperature, differential pressure, and flow rates on SG tube integrity. The licensee has addressed the concerns found in GL 95-03 and Bulletin 88-02 and the staff have found their response acceptable. The staff acknowledges that increased temperature may increase tube susceptibility to circumferential cracking; however, the staff finds that the SG program will continue to provide adequate assurance that SG tube integrity will continue to be maintained. The proposed EPU will not affect the satisfactory performance in maintaining SG tube integrity.

Conclusion

The staff reviewed the licensee's evaluation of the effect of the proposed EPU on SG tube integrity and concludes that the licensee has adequately assessed the continued acceptability of the plant's TSs in terms of the changes in temperature, differential pressure, and flow rates. The 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 TS 6.8.4.j. following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the SG program.

2.1.10 Steam Generator 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 staff's review covered the ability of the SGBS to remove particulate and dissolved impurities from the SG secondary side during normal operation, including condenser in-leakage and primary-to-secondary leakage. The NRC's acceptance criteria for the SGBS are based on 10 CFR Part 50, Appendix A, General Design Criterion (GDC) 14, "Reactor Coolant Pressure Boundary [RCPB]," 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. The staff notes that PTN was designed and constructed based on the 1967 AEC Proposed GDCs, which predate the GDC found in 10 CFR Part 50 Appendix A. As such, the

licensee indicated that PTN GDC-9 and GDC-34 corresponds to 10 CFR Part 50, Appendix A, GDC-14.

PTN GDC-9, “Reactor Coolant Pressure Boundary,” requires that the RCPB be designed so as to have an exceedingly low probability of gross rupture or significant uncontrolled leakage throughout its design lifetime. PTN GDC-34, “Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention,” requires that the RCPB be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failure. Specific review criteria are contained in Standard Review Plan (SRP), Section 10.4.8, “Steam Generator Blowdown System (PWR).”

NRC Technical Evaluation

The licensee stated that the SGBS and components were evaluated to ensure that they are capable of performing their intended functions at EPU conditions. It was reported that the evaluations were performed for an analyzed Nuclear Steam Supply System (NSSS) thermal power of 2660 megawatts thermal (MWt) (the proposed EPU rated thermal power is 2644 MWt). The licensee further stated that the evaluations compared the existing design parameters of systems or components with normal and maximum blowdown flow rates and operating and design pressures and temperatures at EPU conditions.

The licensee reported that the increased steam and feedwater flow rates (feedwater flow rate is expected to increase by 14 percent) at EPU conditions do not significantly affect the concentration of impurities in the turbine cycle and does not increase the effect of the impurities on the SGs. It was also reported that the predictive software used to determine wear rates in components evaluated does not predict any increase in wear rates to the SGBS. As such, the licensee indicated that the SG chemistry is not affected by the uprate. In addition, the licensee stated that no changes to SGBS flow rates and no changes to the operating modes are needed as a result of the EPU.

The operating temperatures and pressures in the SG and interconnecting piping and valves to the blowdown tank are reported to decrease slightly due to the lower SG operating pressure. The licensee reported that the operating temperatures and pressures in the blowdown tank and downstream piping and valves increases slightly due to the increased operating pressure in the number four feedwater heater shell. Despite this increase in temperature and pressure, the licensee indicated that the existing design pressures and temperatures remain bounding for EPU conditions.

The staff has reviewed the licensee’s evaluation and has confirmed that the applicable regulatory guidance was followed and meet the applicable requirements. The licensee has demonstrated that the SGBS is adequate for maintaining secondary-side water chemistry within industry guidelines for maintenance of controlled corrosion rates in secondary system components. The staff concurs that the SGBS will continue to meet system design requirements at EPU conditions.

Conclusion

The staff 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 staff further concludes that the licensee has demonstrated that the SGBS will continue to be acceptable and will continue to meet the requirements of PTN GDC-9 and -34, which corresponds to 10 CFR Part 50, Appendix A, GDC-14, following implementation of the proposed EPU. Therefore, the 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) provides a means for: (1) maintaining water inventory and quality in the reactor coolant system (RCS), (2) supplying seal-water flow to the reactor coolant pumps and pressurizer auxiliary spray, (3) controlling the boron neutron absorber concentration in the reactor coolant, (4) controlling the primary-water chemistry and reducing coolant radioactivity level, and (5) supplying recycled coolant for demineralized water makeup for normal operation and high-pressure injection flow to the emergency core cooling system (ECCS) in the event of postulated accidents. The staff has reviewed the safety-related functional performance characteristics of CVCS components. The NRC's acceptance criteria are based on 10 CFR Part 50, Appendix A: (1) GDC-14, "Reactor Coolant Pressure Boundary (RCPB)," as it requires that the RCPB be designed to have an extremely low probability of abnormal leakage, or rapidly propagating fracture, and of gross rupture, and (2) GDC-29, "Protection Against Anticipated Operational Occurrences," as it requires that the reactivity control systems be designed to assure an extremely high probability of accomplishing their functions in anticipation of and during operational occurances. Specific review criteria are contained in SRP Section 9.3.4, "Chemical and Volume Control System (PWR)."

As was previously stated, PTN is licensed to GDCs that were developed and based on the 1967 Atomic Energy Commission Proposed GDC. As such, the licensee stated that PTN GDC-9 and GDC-34 correspond to 10 CFR Part 50, Appendix A, GDC-14 (see Section 2.1.10, "Steam Generator Blowdown System").

The licensee indicated that there is no specific PTN GDC that is analogous to 10 CFR Part 50, Appendix A, GDC-29. It was reported that the requirements of 10 CFR Part 50 Appendix A, GDC-29 are addressed in the plant's design and licensing basis. Additionally, the licensee indicated that the PTN CVCS does not provide high pressure injection flow to the ECCS in the event of postulated accidents.

NRC Technical Evaluation

The licensee's evaluations were performed to ensure that the CVCS will continue to perform its intended function under EPU conditions. The licensee also reported that the evaluations were conservatively performed for a nominal NSSS thermal power of 2652 MWt (the proposed EPU rated thermal power is 2644 MWt). The RCS fluid interfaces with the CVCS are the regenerative, nonregenerative, seal water, and excess letdown heat exchangers.

The regenerative heat exchanger design process (RCS T_{cold}) inlet temperature is 555 °F, which bounds the highest RCS T_{cold} temperature of 549.2 °F for uprate conditions. The licensee indicated that the charging flow and temperature remains the same at EPU conditions. Thus, it was stated that the performance of the regenerative heat exchanger remains unchanged under EPU conditions. It was reported that the lower inlet temperature into the regenerative heat exchanger will result in a lower inlet temperature to the nonregenerative heat exchanger. The lower inlet temperature to the nonregenerative heat exchanger is reported to be less than the design process inlet temperature of 290 °F.

The nonregenerative heat exchanger is reported to have a letdown tube-side design temperature of 400 °F, which exceeds original inlet temperature of 380 °F during plant heat up. The licensee stated that the original inlet temperature bounds the uprate condition from a mechanical design perspective.

It was stated that the design temperatures for the excess letdown heat exchanger and seal water heat exchanger bounds the temperature parameters under EPU conditions. The excess letdown heat exchanger design temperature is reported to be 555 °F, which bounds the highest inlet temperature of 548.9 °F.

The licensee indicated that since the RCS pressure and CVCS orifice alignment remain unchanged, the charging and letdown flows are not impacted by the EPU. In addition, it was reported that the RCS makeup system is independent of the changes in RCS conditions due to the proposed EPU, as a result, the licensee stated that the EPU will not affect the performance of the makeup water system in performing its intended function.

The CVCS has the capability of meeting the required increase in RCS boron concentrations. The licensee stated that the TS limits for the minimum boron concentration range, minimum inventory, and the minimum room temperature for the boric acid storage tanks have been updated to address the effect of the change in the limiting moderator temperature coefficient on the required boration levels at EPU conditions.

The letdown flow path is routed inside containment such that there is adequate residence time to permit the decay of nitrogen 16 (N-16) before the letdown fluid leaves the containment building. Further, it was reported that the N-16 levels will increase slightly in proportion to the increase in reactor power level, but that the N-16 dose increase due to the EPU conditions is insignificant. The licensee evaluated the increase in N-16 and the NRC staff determined that it is acceptable.

The licensee stated that the evaluations of the CVCS charging, letdown, and RCS makeup performance show that the CVCS is able to perform its intended function without modifications to the system. The licensee indicated that the boration capability of the CVCS for core reactivity control will be addressed during the Westinghouse reload safety evaluation process for each reload cycle, but that minimum boron concentration limits for plant cooldown were determined for use in future reload safety analysis checklists to ensure that adequate reactivity shutdown margin is available for any post shutdown time.

The staff has reviewed the licensee's evaluation and has confirmed that the applicable regulatory guidance was followed. The licensee has demonstrated that the CVCS will continue to maintain RCS inventory and water chemistry. The staff determined that the CVCS will continue to meet system design requirements and that no new design transients will be created at EPU conditions.

Conclusion

The staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the CVCS and concludes that the licensee has adequately addressed changes in the temperature of the reactor coolant and its effects on the CVCS. The staff further concludes that the licensee has demonstrated that the CVCS will continue to be acceptable and will continue to meet the requirements of PTN GDC-9 and GDC-34 and licensing basis, which corresponds to 10 CFR Part 50, Appendix A, GDC-14 and GDC-29, following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the CVCS.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

Structures, systems, and components (SSCs) important to safety at nuclear power plants could be impacted by the dynamic effects of a high energy line break (HELB). The Nuclear Regulatory Commission (NRC) staff conducted a review of the pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures. The NRC staff's review included: (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 inservice inspection 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 extended power uprate (EPU) may have on items 1 through 4 above.

The NRC staff's acceptance criteria are based on Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants," GDC-4, Environmental and Dynamic Effects Design Bases," which requires SSCs important to safety to be designed to accommodate the dynamic effects of a postulated HELB. Specific review criteria are contained in the NRC's NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [Light-Water Reator] Edition," (SRP), Section 3.6.2 and other guidance provided in Matrix 2 of RS-001, "Review Standard for Extended Power Uprates." Section 1.3, "General Design Criteria," of the PTN Final Safety Analysis Report (FSAR) indicates that the GDCs documented in the PTN FSAR are similar in content to the Atomic Industrial Forum (AIF) versions of the proposed (1967) GDCs, instead of the GDCs documented in 10 CFR Part 50, Appendix A. The GDCs used during the licensing of PTN predate the GDCs documented in 10 CFR Part 50, Appendix A. The NRC staff notes that

the plant-specific general design criterion, PTN GDC-40, referenced in Appendix A.2, "High Energy Pipe Failure Outside Containment," of the PTN FSAR is similar to GDC-4. The NRC staff additionally notes that SRP Section 3.6.2, "Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment," was also issued after the construction permits for PTN were issued. PTN, Unit 3 began commercial operation on December 1970. PTN, Unit 4 began commercial operation in October 1972. Therefore, the NRC staff utilized the current licensing basis (CLB) HELB postulation methodology found in the PTN Updated Final Safety Analysis Report (UFSAR), Sections 5.1.1, 5.4.1, 5.4.2, 5.4.3, and Appendix 5E for review of the EPU License Amendment Request (LAR) Sections 2.2.1 and 2.5.1.3.

The NRC staff has previously evaluated the PTN pipe rupture and associated dynamic effects in support of the license renewal efforts relative to PTN. The NRC staff's SER regarding the PTN license renewal was completed in April, 2002[25] and supplemented in May 2002[26] in the NUREG-1759, "Safety Evaluation Report Related to the License Renewal of the Turkey Point Nuclear Plant, Units 3 and 4."

NRC Technical Evaluation

The CLB for the postulation of HELBs outside containment at PTN is documented in Section 5.4.3 of the PTN FSAR. In accordance with the CLB at PTN, high-energy pipe break locations are selected in accordance with the criteria documented in an Atomic Energy Commission (AEC) transmittal from A. Giambusso to applicants and licensees entitled, "General Information Required for Consideration of the Effects of a Piping System Break Outside of Containment" (the "Giambusso Letter"). There is no change in the pipe rupture protection criteria for the protection of components from jet impingement, placement of missile shields, and whip restraints from the CLB for EPU conditions, and therefore is acceptable to the staff. In 1995, the NRC approved the leak before break analysis to eliminate the dynamic effects of postulated pipe ruptures in the hot, cold, and crossover legs of the reactor coolant primary loop piping for PTN, Units 3 and 4. The staff finds this acceptable for EPU evaluations because the licensee will be using the same methodology as the CLB.

The licensee is continuing the same HELB methodology for EPU that was previously used by the licensee for the CLB prior to EPU, as well as for license renewal. In its response to a staff's request for additional information (RAI), the licensee confirmed that the criteria for determining pipe rupture locations and the associated dynamic effects for EPU considerations are the same as those for the PTN CLB. There is no change in the pipe rupture protection criteria for the protection of components from jet impingement, placement of missile shields, and whip restraints from the CLB for EPU conditions. Florida Power & Light Company (FPL) postulated high energy line breaks for the following systems outside containment, namely main steam, main feedwater (MFW), auxiliary feedwater, steam generator blowdown, chemical and volume control system, and residual heat removal. The licensee performed evaluations for these piping systems to address the impact of EPU operating conditions, pressures, temperatures, and flows, and reviewed the piping system stress levels on the EPU. In response to the staff's RAI regarding the impacts to existing pipe rupture locations and associated dynamic effects due to MFW piping modifications associated with the replacement of the numbers 5 and 6 MFW

[25] ML021280496 and ML021280532
[26] ML021560094

heaters for both the PTN units to support EPU, the licensee provided a summary of stress results and break postulations demonstrating that there are no new or different break locations for the MFW system as a result of EPU. Based on staff's review of the summary of these evaluations, the NRC finds that the licensee has adequately demonstrated that there are no new or revised break locations, and the design basis for pipe break, jet impingement, and pipe whip considerations remain valid for the EPU.

In response to the staff's RAI pertaining to the need for the completion of the evaluations for the shield equipment associated with the replacement of the sixth MFW heater and the nozzle modification in support of the EPU, the licensee completed the design and provided a summary for both units of PTN. The licensee stated that the only HELB analysis outside containment affected by EPU is the main feedwater system because the number 6 feedwater heater discharge nozzle size increased from 18 inches to 24 inches nominal diameter. In accordance with the HELB criteria, the licensee postulated terminal end breaks at the discharge nozzles of the replaced sixth MFW heaters. The licensee performed walkdowns around the number 6 MFW heater outlet pipes and identified equipment important to safety. The licensee made a conservative decision to install deflector shields on the discharge nozzles and not to use any zone of influence criteria for EPU HELB analysis. The licensee noted that three safety-related pressure transmitters in Unit 3 and three safety-related pressure transmitters in Unit 4 may be influenced by a circumferential MFW pipe rupture at the outlet nozzle terminal ends. These components are located within the main steam valve platform trestle area. To protect these safety-related components, new deflector shields will be installed on the MFW outlet piping at the postulated circumferential break locations at each of the number 6 MFW Heater outlet nozzles. The shields are designed to redirect jet forces and guide streams in a direction away from the safety-related equipment. Based on a review of the above information regarding the number 6 MFW heater replacement, the staff agrees that the licensee has performed adequate evaluations for the terminal end breaks at the sixth MFW heater nozzles to ensure the integrity of the safety-related equipment in the vicinity.

In 1995, NRC approved the leak before break analysis to eliminate the dynamic effects of postulated pipe ruptures in the hot, cold, and crossover legs of the reactor coolant primary loop piping inside the containment for PTN Units 3 and 4. The licensee will continue to use the same methodology for the EPU.

Based on the review of the information relative to the licensee's HELB postulation methodology, the NRC staff finds the methodology acceptable, as it is the same methodology that was used for the CLB. This acceptability is based on the licensee's demonstration that the methodology provides reasonable assurance that the regulatory requirements applicable to HELBs will continue to be satisfied following implementation of the proposed EPU at PTN.

Pipe stress analysis reevaluations performed by the licensee as a result of EPU conditions did not result in any new pipe breaks or modifications for existing pipe break locations. The NRC staff notes that, due to EPU implementation, the licensee has identified no new locations where breaks are to be postulated in accordance with the HELB postulation methodology. The NRC staff considers the licensee's assessment acceptable based on the acceptability of the licensee's methodology used to postulate these breaks, as outlined above. The NRC staff considers the licensee's assessment acceptable based on the fact that the licensee utilized the

current licensing basis methodology for evaluating the effects of HELBs in assessing the effects due to a postulated HELB.

Conclusion

The NRC staff reviewed the licensee's evaluations related to the 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 intent of the requirements of 10 CFR Part 50, Appendix A, 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 Supports

Regulatory Evaluation

The NRC staff has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (B&PV Code), Section III, Division 1 and ASME/ANSI [American National Standards Institute] B31.1, "Power Piping Code"; and the GDCs discussed below. 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, where applicable, fatigue cumulative usage factors (CUFs) against the code-allowable limits. The NRC acceptance criteria are based on the 10 CFR 50.55a, "Codes and standard," and on the GDCs specified in 10 CFR 50, Appendix A, discussed below. The GDCs used during the licensing of PTN predate the GDCs provided today in 10 CFR Part 50, Appendix A. As noted in Section 1.3, "General Design Criteria," of the PTN UFSAR, the PTN GDCs were developed based on the 1967 Atomic Energy Commission Proposed General Design Criteria. However, as stated above, because PTN is not licensed to 10 CFR Part 50, Appendix A GDCs, the staff, in reviewing the structural integrity of the SSCs for the proposed EPU, used the PTN licensed GDCs, which are described below with a comparison of the equivalent 10 CFR Part 50, Appendix A GDCs. 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.

- 10 CFR 50.55a, which requires that safety-related pressure-retaining components of fluid systems meet applicable code requirements; and GDC-1, "Quality Standards and Records," 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.

  PTN has committed to comply with 10 CFR 50.55a through its Quality Assurance Topical Report.

GDC-1, requires that those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary.

- GDC-2, requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions.

  PTN GDC-2 requires systems and components of reactor facilities to withstand forces imposed by extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice.

- GDC-4, requires that structures, systems, and components important to safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.

  PTN has no plant-specific GDC analogous to 10 CFR Part 50, Appendix A, GDC-4. However, similar requirements are addressed under PTN's environmental qualification (EQ) program. The PTN UFSAR Appendix 8A describes that equipment required to mitigate or monitor the consequences of a design basis accident must be capable of maintaining functional operability under conditions postulated to occur during its installed life as embodied in 10 CFR 50.49.

- GDC-14, 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 fracture.

  PTN GDC-34 requires that the RCPB shall be designed and operated to reduce to an acceptable level on probability of rapidly propagating type failures.

- GDC-15, requires that the reactor coolant system (RCS) be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation.

  PTN has no plant-specific GDC analogous to GDC-15 on RCS design, but such requirements are addressed in the plant design as summarized below.

  As described in the UFSAR, Section 4.1.3, the RCS, in conjunction with its control and protective provisions, is designed to accommodate the system pressures and temperatures that occur under all expected modes of plant operation or anticipated system interactions, and maintain the stresses within applicable code stress limits.

> The RCS conditions resulting from anticipated transients or malfunctions are monitored and appropriate action is automatically initiated to maintain the required cooling capability and to limit system conditions to a safe level. The RCS is protected from overpressure by means of pressure relieving devices, as required by Section III of the ASME B&PV Code.

In addition to their GDC compliance described above, PTN pressure-retaining components and supports were evaluated for license renewal. The evaluations are documented NUREG-1759.

<u>NRC Technical Evaluation</u>

Nuclear Steam Supply System Piping, Components, and Supports

PTN, Units 3 and 4 nuclear steam supply system (NSSS) piping, which is the RCS piping system, consists of three heat transfer piping loops connected in parallel to the reactor pressure vessel (RPV). The licensee's EPU Licensing Report (LR) indicates that the PTN current design basis for NSSS piping, components and supports is contained in FSAR Sections 3.1, "Reactor Design Basis," 3.2, "Reactor Design," 4.0, "Reactor Coolant System," 4.1, "Reactor Coolant System; Design Basis," 4.2, "RCS System Design and Operation," 4.4, "Testing and Inspections," 5.1, "Containment Isolation System," 6.1, "Engineered Safety Features Criteria," and Appendix 5A, "Seismic Design Analysis." In addition, the existing design-basis also includes the pressurizer surge line thermal stratification, requested by NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification."

The NRC staff notes that the PTN NSSS piping evaluations and qualifications for EPU conditions utilized the American Standards Association (ASA) Code for Pressure Piping B31.1 (ASA B31.1 Code), 1955 Edition, as this is the code used in the existing plant design basis analysis of record evaluations for PTN. There is no fatigue analysis performed for the reactor coolant loop (RCL) piping. 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 RCS supports (SG, RCP and pressurizer) were designed using the American Institute of Steel Construction (AISC) Manual, 1963 Edition.

The licensee evaluated the existing design basis analyses for the RCL piping and associated branch piping, RCL primary equipment supports and the pressurizer surge line to assess the impacts associated with the implementation of EPU. Specifically, the following items were evaluated as applicable by the licensee for the EPU program using EPU parameters:

- RCL loss-of-coolant accident (LOCA) analysis using loop LOCA hydraulic forces and the associated loop LOCA RPV motions,
- RCL piping stresses,
- RCL displacements at auxiliary piping line connections to the centerline of the RCL at branch nozzle connections and impact on the auxiliary piping systems,
- Primary equipment nozzle loads,
- RCL piping system leak-before-break (LBB) loads for LBB evaluation,
- Pressurizer surge line piping analysis including the effects of thermal stratification, and
- RCL primary equipment support loads (Reactor Vessel, Steam Generator, Reactor Coolant Pump and Pressurizer).

The licensee reviewed the design parameters that will change due to the EPU for impact on the existing RCL piping and the auxiliary lines attached to the RCL centerline at the RCL branch nozzle connections.

The current design basis structural analysis of the RCL piping was performed for all applicable loadings such as deadweight, thermal expansion, maximum potential earthquake (MPE) cases, and LOCA cases. The current design basis analysis models for these loading cases were evaluated as applicable to reflect the EPU conditions.

In its response to the staff's RAI regarding primary equipment support activity in the seismic analysis of the RCL piping, the licensee clarified that the RCL piping and support system includes one way horizontal bumpers on steam generators and reactor coolant pumps. Support activity refers to the modeling of the one way bumpers in linear seismic analysis using the response spectrum method utilizing various support activity cases. The staff reviewed the licensee's response and finds it acceptable because the technical approach of modeling one way supports in seismic analysis is sound and adequately described.

In response to the staff's request regarding the combination method for RCL stresses from MPE and LOCA, the licensee stated that square-root–sum-of-squares (SRSS) methodology was used. This is acceptable to the staff because MPE and LOCA are faulted events and the use of the SRSS combination is reasonable.

The licensee responded to the staff's request regarding the use of various editions of the B31.1 Code and the AISC Manual of Steel Construction for pipe stress analyses and pipe support evaluations, respectively, stating that justifications and reconciliations were performed. Based on a review of the licensee's response, the staff agrees that the licensee provided an adequate justification in reconciling the differences.

The EPU structural evaluation of the RCL piping system performed by the licensee included assessment and/or analysis as applicable for deadweight, thermal expansion, and MPE loading conditions. For the EPU program, new LOCA analyses were performed for three postulated breaks of the auxiliary lines, namely, the 10-inch accumulator line break on the cold leg, the 14-inch residual heat removal line break on the hot leg, and the 12-inch surge line break on the hot leg. The current design basis deadweight analysis was evaluated by the licensee for the EPU considering the weight of the RCL piping and the primary system water weight.

The thermal analysis performed by the licensee for the EPU program evaluated the RCL for the lower-bound temperature and the upper-bound temperature. The RCL was evaluated for two temperature cases – first for the lower-bound temperature case and the second for the upper-bound temperature. The above two thermal cases of the RCL were evaluated to envelope the RCL temperatures and the steam generator tube plugging data.

The MPE seismic analysis methods and the seismic MPE input response spectra for the EPU parameters are the same as those used in the current design basis analysis.

The licensee also reviewed the results of the analysis performed to assess the effects of the EPU conditions on the structural integrity of NSSS piping, components, and their supports with the results of the PTN License Renewal Application, to determine their impact on license

renewal. Based on a review of the results of the analysis, the staff agrees that the analytical results associated with the PTN operating at EPU conditions do not impact the license renewal scope, aging effects, and aging management programs as a result of the EPU conditions.

Based on a review of the evaluations performed by the licensee for the EPU program using NSSS design parameters, NSSS design transients, loop LOCA hydraulic forcing functions and associated RPV motions, it is concluded that there is no adverse effect on the RCL current design basis, RCL piping deadweight, thermal, and seismic analyses and evaluations, and the results in the current design basis remain acceptable for the EPU program for these above stated loading conditions. Additionally, the staff finds the new LOCA analyses and evaluations, and results for the EPU program acceptable.

The maximum RCL piping stresses for the EPU program and the corresponding code-allowable stress values are presented in LR Table 2.2.2.1-1, Turkey Point Unit 3 and Unit 4: Maximum RCL Piping Stress Summary.

The staff notes that the RCL piping stresses are combined in accordance with the methods as specified in the ASA B31.1 Code criteria and UFSAR Table 5A-1, and are within the allowable limits, and therefore, are acceptable for the EPU.

The applicable RCL piping primary equipment (reactor vessel, steam generator, reactor coolant pump, and pressurizer) support loads for the EPU parameters obtained from the RCL piping analysis were utilized for evaluation of the structural acceptability of the respective supports. The primary equipment nozzle loads were compared to the allowable, as defined in the equipment design specifications and in the current design basis. The staff found that the nozzle loads are acceptable and the EPU Program has no adverse impact on the analysis results. The staff finds that the applicable RCL piping loads resulting from the range of operating temperatures were utilized by the licensee in evaluation to confirm the LBB and found that the proposed EPU is acceptable for LBB.

The impact of the EPU program parameters on the RCL piping loads and displacements at the intersection of the centerline of the RCL piping and the auxiliary line piping system branch nozzle connections were utilized for the qualification and acceptance of the auxiliary lines for the EPU program.

For the pressurizer surge line, the impact of the design transients with respect to the thermal stratification and fatigue analysis is controlled by the temperature difference (ΔT) between the pressurizer temperature and the hot-leg temperature and was evaluated. The controlling ΔTs for the pressurizer surge line are associated primarily with the plant heatup and cooldown events which are not affected by the EPU program.

The current design basis pressurizer surge line analysis results, including the effects of thermal stratification, are applicable for the EPU program and meet the acceptance criteria for the EPU program.

The quality standards, seismic and environmental requirements, and reactor coolant pressure boundary capabilities applicable to the RCS and its supports have been adequately evaluated for impact by the EPU conditions and therefore, the staff finds the results acceptable.

FPL has adequately assessed the effects of the proposed EPU on the structural integrity of the NSSS piping, components, and their supports. Based on a review of the results of the evaluations performed by the licensee, the NRC staff concludes that the NSSS piping, components, and their supports will continue to meet the requirements of its current licensing basis with regard to 10 CFR 50.55a and PTN GDCs 1, 2, and 34. Therefore, based on its review as summarized above, the NRC staff finds that the NSSS piping, components and supports are structurally adequate for the proposed EPU conditions.

Balance-of-Plant Piping, Components, and Supports

The licensee evaluated the balance-of-plant (BOP) piping, components and supports inside and outside containment to assess the impact of operating temperature, pressure and flow rate changes that will result due to the implementation of EPU, in accordance with the current design basis criteria. Piping evaluations and qualifications in CLB utilized the ASA B31.1 Code, 1955 Edition. For design and analysis of pipe supports in the CLB, the American Institute of Steel Construction (AISC) Manual, 1963 Edition was utilized.

The piping evaluations and qualifications for EPU utilized the American National Standards Institute (ANSI) B31.1 Power Piping Code, 1973 Edition through winter 1976 Addenda. For EPU design and analysis of pipe supports, the AISC Manual, 8^{th} Edition was utilized. The licensee in its response to the staff's RAI, provided justification which technically reconciled the later code editions utilized for EPU to the original code of construction.

The EPU LAR states that the impact of EPU on the BOP piping, pipe supports, and associated equipment was evaluated for EPU conditions. This evaluation by the licensee includes all Class I and portions of Class III piping that are part of the BOP piping systems. These systems are: auxiliary feedwater, auxiliary steam, chemical and volume control, circulating water, component cooling water, condensate and feedwater, containment spray, extraction steam, feedwater heater vents and drains, intake cooling water system, main steam and steam dump (turbine bypass) system residual heat removal, safety injection, spent fuel pool cooling, service water, steam generator blowdown, and turbine plant cooling water.

The NRC staff's review of the EPU LAR identified that the structural design and analysis of some BOP components, piping and supports at EPU conditions, namely CCW piping support modifications, main steam piping support modifications and feedwater pipe support modifications associated with the replacement of number 5 and number 6 feedwater heaters, and spent fuel pool supplemental heat exchanger associated modifications had not been completed. In response, the licensee subsequently completed and provided summaries of the qualifications for the CCW, main steam, and feed water heater replacement associated modifications. The staff reviewed the summaries and determined that they are acceptable because they are capable of maintaining their structural integrity for EPU conditions, by meeting the applicable code allowable limits. However, for the spent fuel pool supplemental heat exchanger associated modifications, the licensee has not completed the evaluations and the staff has identified the following license condition:

> Prior to completion of the Cycle 26 refueling outage for Unit 3 and cycle 27 refueling outage for Unit 4, the licensee shall provide confirmation to the NRC

staff that the design, structural integrity evaluations, and installation associated with the modifications related to the spent fuel pool supplemental heat exchangers are complete, and that the results demonstrate compliance with the appropriate FSAR and code requirements. As part of the confirmation, the licensee shall provide a summary of the structural qualification results of the piping, pipe supports, supplemental heat exchanger supports, and the inter-tie connection with the existing heat exchanger for the appropriate load combinations along with the margins.

System operation at EPU conditions could result in increased pipe stress levels and pipe support and equipment nozzle loads due to slightly higher operating temperatures, pressures and flow rates internal to the piping. The licensee evaluated the impact of EPU on BOP piping systems due to changes in operating parameters such as pressure, temperature and flow rate to demonstrate design basis compliance in accordance with the applicable criteria.

The licensee determined the thermal and pressure change factors or ratios to compare and evaluate the changes in the EPU operating conditions.

The thermal change factor was determined using the ratio based on the mean coefficients of expansion (α) and temperatures (T) in degrees Fahrenheit (°F) for the EPU and design basis conditions. The thermal change factor is $[(\alpha_{EPU})(T_{EPU}-70°F)] / [(\alpha_{design\ basis})(T_{design\ basis}-70°F)]$.

The pressure change factor is the ratio of pressures $(P_{EPU})/(P_{design\ basis})$

When the change factors are less than or equal to 1.0, it is determined that the current condition envelopes or equals the EPU condition, and therefore the piping system is concluded to be acceptable for the EPU conditions.

For change factors greater than [>] 1.0, it is determined that additional evaluations are performed by the licensee to address the specific increase in temperature and/or pressure in order to document the design basis compliance. These evaluations were performed in accordance with the PTN piping and support analysis requirements. The change factor approach used by the licensee for the evaluation of the impact of EPU is acceptable to the staff because these factors properly account for the pressure and temperature change effects.

Flow rate increases and their impact on potential flow induced fluid transient loads were evaluated for the main steam and feedwater piping systems. The remaining piping systems that experience flow rate increases from the EPU, such as condensate, extraction steam, heater drains, but do not contain any fast closing valves, do not experience significant flow induced fluid transients. Flow induced fluid transients in BOP piping, such as heater drains and extraction steam, during plant startup and shutdown, where voids could be present, are normally small. Hence, the flow rate increases for these systems can be concluded to be acceptable without further evaluation.

There were no changes to seismic inputs resulting from EPU, and therefore, the existing seismic design basis for piping and supports remains valid and is unaffected by EPU. Hence,

the BOP piping and support loadings will continue to meet the PTN current licensing basis with respect to the requirements of GDC-1 through GDC-5.

In addition to the methodology described above, the licensee performed plant walkdowns on portions of the BOP piping systems to review the piping layouts and support configurations to assess the adequacy of the deadweight spans and to review the thermal flexibility of the installed piping systems. In response to the staff's RAI regarding the plant walkdowns, the licensee clarified that those walkdowns were on portions of the nonsafety-related condensate system to ensure adequate thermal flexibility and deadweight spans.

In response to the staff's RAI about the licensee's use of five different computer programs, namely NUPIPE-SWPC, PC-PREPS, STEHAM-PC, WATHAM-PC, and ANSYS/Mechanical, that are not currently described in the UFSAR, to perform the EPU piping stress evaluation, piping welded attachment stress evaluation, and for the generation of fluid transient forcing functions, the licensee provided a basis stating that these computer software programs are fully qualified for nuclear applications and are widely used in the nuclear industry. In addition, these programs were previously used in many power uprate projects including the ones for R. E. Ginna Nuclear Power Plant, Beaver Valley Power Station, and Point Beach Nuclear Plant. Using an approved quality assurance program, the licensee verified and validated these computer programs to be accurate. The basis provided by the licensee is satisfactory to the staff because these programs are qualified and widely used in the industry, including in power uprate applications.

For BOP piping systems that required detailed analyses to reconcile the EPU operating parameters, the licensee provided a summary of revised pipe stress levels corresponding to the EPU conditions. The results presented include existing stress levels, revised stress levels for EPU conditions, allowable stresses for the applicable loading condition, and the resulting design margin for each piping analysis that was evaluated to reconcile the EPU conditions. The design margin provided is based on the ratio of the calculated stress for EPU divided by the allowable stress. Additionally, all stress levels resulting in design margins less than or equal to [≤]1.0 are acceptable, in accordance with the ASME Code, Section III and ANSI B31.1 codes of record.

The staff requested additional clarification regarding the stress summaries listed in the LR Tables 2.2.2.2-1 and 2.2.2.2-2. In response, the licensee clarified several items, such as: (i) various load combinations, and stress criteria limits utilized in accordance with ANSI B31.1 Code and UFSAR, (ii) corrections to G+E combination to P+G+E combination, where P, G, E are stresses due to pressure (P), gravity (G), and thermal expansion (E); (iv) evaluation of the feedwater system for water hammer fluid transient loading. The staff reviewed these clarifications and corrections and finds them acceptable.

In response to the staff's request on containment penetration anchor qualification of main steam, feedwater, and CCW systems for the impact of EPU, the licensee responded by stating that the piping stress levels at these penetration anchor locations are within the allowable limits. The staff requested additional information to demonstrate that these anchors qualify for loads and moments combined from both sides of the anchor because the piping stress qualification is based only on moments from one side at that location. In its response, the applicant provided a summary of the evaluations for main steam, feedwater, and CCW containment penetration anchors. Based on a review of the summary of evaluations, the staff finds it acceptable

because the applicant adequately demonstrated that the containment penetrations meet the applicable acceptance criteria considering all loading components acting from both sides of the containment penetration anchor for the EPU conditions.

The licensee has also evaluated the impact of the EPU on the conclusions reached in the PTN safety evaluation report (SER), NUREG-1759 for BOP piping and supports.[27] The staff concluded that the aging evaluations that were approved by the NRC in the SER for the PTN license renewal, for BOP piping and supports remain valid for EPU conditions. The time-limited aging analyses evaluations applicable to BOP piping remain bounding for the EPU conditions.

The LAR Tables 2.2.2.2-1 and 2.2.2.2-2 provide a summary of current pipe stress levels, revised stress levels for EPU conditions and the resulting design margins for each piping analysis that required detailed evaluation to reconcile for EPU conditions. These tables include the RCL branch piping that was impacted by EPU. Piping systems not specifically listed in LR Tables 2.2.2.2-1 and 2.2.2.2-2 did not require a detailed evaluation (i.e., no significant operating parameter increase due to EPU) to reconcile for EPU conditions nor did they involve piping systems which will experience plant modifications, such as the piping associated with the Number 5 and 6 feedwater heater replacements. The stress results reported incorporate thermal expansion and fluid transient increases, as applicable, that were reconciled as part of the EPU evaluations.

In addition to those piping systems, as discussed above, which are directly affected by the EPU operating conditions, there are those piping systems which are indirectly affected by EPU. Specifically, this indirect affect is through major plant modifications which are required to support operation at EPU conditions. For these situations, the piping and support evaluations are performed as part of the plant modification process associated with each of these specific plant modifications.

The piping stress evaluations performed concluded that all piping systems remain acceptable and will continue to satisfy design basis requirements when considering the temperature, pressure and flow rate effects resulting from the EPU conditions. The piping evaluations also concluded that the feedwater and main steam systems (MSS) can withstand fluid transient loads, such as water hammer and steam hammer, associated with EPU conditions.

The results of the pipe support evaluations for systems impacted by the EPU concluded that supports remain acceptable. The licensee also summarized required modifications to certain main steam and component cooling water system pipe supports to accommodate the revised loads due to EPU conditions.

The results of the equipment nozzle evaluations concluded that these components remain within acceptable limits for EPU conditions.

The pipe stress analysis reevaluations that were conducted at the EPU conditions did not result in any new pipe breaks or modifications to the existing pipe break locations. Hence, the existing conclusions reached with respect to pipe break evaluations continue to remain valid for EPU.

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[27] ML11118A0250

In summary, the BOP piping systems will continue to meet the PTN current licensing basis with respect to the requirements of the applicable GDCs.

Additionally, the staff agrees that the implementation of EPU will result in higher flow rates for some of the BOP piping systems within the main power cycle, such as, main steam, feedwater, and condensate. The licensee reviewed these piping systems for potential vibration issues and included those as part of the start-up testing program, which is related to the overall implementation of the EPU.

Based on a review of the summaries of the EPU evaluations performed by FPL, the staff concludes that the licensee has adequately assessed the effects of the proposed EPU on the structural integrity of BOP pressure-retaining components and their supports. FPL concludes that the above evaluations have adequately accounted for the effects of the proposed EPU on the BOP piping, components, and supports. Based on the information above, the staff concludes that the BOP pressure-retaining components and their supports will continue to meet the structural integrity of its current licensing basis with regard to 10 CFR 50.55a and PTN GDCs 1, 2, and 34, when the applicable support modifications are implemented.

Reactor Vessel and Supports

The reactor pressure vessel (RPV) is the principal component of the RCS and contains the heat-generating core, core support structures, control rods, and other components directly associated with the core. The RPV primary outlet and inlet nozzles provide for the exit of the heated coolant and its return to the RPV for recirculation through the core. The PTN RPV is cylindrical, with a welded hemispherical bottom head and a removable, flanged and gasketed, upper head. The RPV is described in PTN UFSAR Chapter 3, Reactor, and Chapter 4, Reactor Coolant System. The RPV is supported at the three inlet (cold leg) nozzles and the three outlet (hot leg) nozzles. The reactor vessel closure heads (RVCH) for PTN, Units 3 and 4 were replaced during the 2004 and 2005 refueling outages with the replacement of the control rod drive mechanisms (CRDMs) and associated closure head components. The original code of construction for the RPV is the ASME Code, Section III, 1965 Edition through the summer 1966 Addenda. The RPV supports were designed to the requirements of the 1963 Edition of the AISC Manual of Steel Construction.

The replacement RVCH (RRVCH), replacement CRDMs and associated closure head components were designed, fabricated, inspected and tested in accordance with the requirements of the applicable Westinghouse and AREVA design specifications and the ASME B&PV Code Section III, Class 1, 1989 Edition. For the RRVCH EPU evaluations, the licensee used the ASME B&PV Code Section III, Class 1, 1989 Edition except that Appendix F of ASME B&PV Code Section III, 2004 Edition was used for the faulted (normal plus LOCA combination) condition. In response to the staff's RAI regarding reconciliation on the use of later codes, the licensee provided a summary table listing the applicable component, Code for CLB, code used for EPU evaluations and noting that ASME Code, Section XI reconciliation was performed for PTN to evaluate the differences between the original codes of construction and the later edition of the ASME Code used for the fabrication and analysis of their replacements. The staff finds it acceptable because code reconciliations justifying the use of later editions of the Code were

performed. The reactor vessel and vessel supports were evaluated for plant license renewal. The evaluations are documented in NUREG-1759.

In response to the staff's request for clarification on why some of the EPU stress intensities and CUF values are smaller than the pre-EPU values for RPV and supports, and whether the listed CUF values in LR Table 2.2.2.3-1 are for 40 or 60 years life, the licensee clarified that the CUF values are for 60 years. The licensee also clarified that the pre-EPU results were based on conservative methods and factors, while the EPU evaluations used finite element analysis with realistic (actual) transients that contributed to reduced stress intensity ranges and CUF values. The staff also sought clarification regarding why the RPV support loads due to a maximum hypothetical earthquake at EPU are lower than the corresponding loads for the design basis. In response, the licensee provided clarification that the seismic loads on the RPV supports for the EPU program were developed using sophisticated nonlinear dynamic analysis methods which potentially contributed to the reduced seismic loads on the RPV supports. The staff finds the above clarifications by the licensee satisfactory.

To address the staff's RAI regarding the basis for the allowable loads for RPV support critical components in LR Table 2.2.2.3-6, the licensee provided the basis which uses physical properties, material properties, applicable load combinations, and the 1963 Edition of the AISC Manual. However, the staff noted that the licensee was utilizing the Certified Material Test Reports (CMTR) yield strength value for EPU evaluations for faulted load combination. By an RAI, the staff requested that the licensee utilize code-based minimum yield strength value rather than the CMTR value. The licensee recalculated the RPV support component allowable loads based on the code-based yield strength, and demonstrated the structural integrity of the RPV support components for the faulted condition by October 31, 2011. Based on a review of the RAI response by the applicant, the staff finds the RPV components will perform their intended function.

The licensee performed a structural analysis and evaluation of the RPV structure using the revised loads for impact by EPU conditions. The NRC staff reviewed the licensee's summaries of the maximum stress intensity range and CUF evaluations for RPV outlet nozzles and support pads, inlet nozzles and support pads, shell-to-shell juncture, bottom head to shell juncture, core support pads, and bottom mounted instrumentation nozzles, along with the licensee's responses to the staff's RAIs. The NRC staff reviewed the licensee's evaluation of the effects of the proposed EPU on the structural integrity of PTN's RPV and supports and concludes that the licensee has demonstrated that the RPV and supports will remain structurally adequate to perform their function at proposed EPU conditions and will continue to meet the requirements of PTN GDCs 1, 2, 4 and 10 and the ASME Code, Section III for Class 1 components, following implementation of the proposed EPU.

Control Rod Drive Mechanism

The control rod drive mechanisms (CRDMs) are located on the RPV head and are coupled to the rod control cluster assemblies (RCCAs). The primary function of the CRDMs is to insert, withdraw, or hold stationary RCCAs within the core to control average core temperature and to shutdown the reactor. During the 2004 and 2005 refueling outages, the RVCH, forty five CRDM assemblies four core exit thermocouple nozzle adapters, two reactor vessel level monitoring system nozzle adapters, two CRDM spare plugs, and associated components were replaced.

The Westinghouse model Model L-106B CRDMs consist of the internal latch assembly, pressure vessel, operating coil stack, drive shaft assembly, and rod position indicator coil stack. The CRDM housings are threaded and seal welded to the reactor vessel head penetrations. The function of the CRDM housings is to maintain pressure boundary integrity. The replacement CRDMs were designed and fabricated in accordance with the requirements of ASME Code, Section III, Class 1, 1989 Edition.

The NRC staff reviewed the licensee's evaluation of the CRDM and its components as summarized in EPU LR Section 2.2.2.4 and the licensee's responses to the staff's RAI. The licensee employed the current design basis and codes of record to evaluate the RCPB structural integrity of the PTN CRDMs considering the current design analysis of record (AOR) evaluations and the NSSS operating parameters of EPU (LR Section 1.1) and the EPU NSSS design transients (LR Section 2.2.6) for the PTN. The applicable loadings include pressure, deadweight, seismic, thermal and transient loads. Pressure, deadweight and seismic loads are unaffected by the EPU. The hot leg temperature (RPV outlet temperature) is 617 °F maximum for EPU and is bounded by the 618 °F used in the current design analyses of record. The licensee compared the EPU NSSS design transients against those used in the current analyses to evaluate the PTN CRDMs and determined that the EPU program NSSS design transients were bounded. Therefore, the results of the AOR remain bounding and valid at EPU for the CRDMs. The results summary provided by the licensee for the CRDMs consisted of the CUF values only. In response to the staff's RAI to include a summary for the primary membrane and membrane plus bending stress intensities, and the corresponding allowable limits, the licensee provided that information. The NRC staff reviewed the stress intensity summary and the fatigue CUF and finds them acceptable for EPU because they meet the ASME Code of record allowable values. The licensee also concluded that the proposed EPU has no impact on the license renewal evaluations.

The licensee did not change the Code utilized or analysis methodology for the CRDMs. The design transients remain bounding for EPU. The results of the structural analysis of the CRDMs including the CUFs calculated for pre-EPU remain valid for the EPU conditions. The licensee, using the current plant design basis methodology to evaluate the pressure boundary components of the CRDMs, has demonstrated that these components will continue to meet the code of record with regard to 10 CFR 50.55a, and PTN GDCs 1, 2, and 34, following the implementation of the proposed EPU. Therefore, based on its review, the NRC staff finds the proposed EPU acceptable with respect to the structural integrity of the pressure retaining components of the CRDMs.

Steam Generators and Supports

The original PTN steam generators (SGs) were designed and constructed to the requirements of the 1965 Edition of the ASME B&PV Code, Section III, summer 1965 Addenda. The original SG lower assemblies for PTN Units 3 and 4 were replaced in 1982 and 1983, respectively. The replacement assemblies were fabricated to the requirements of the 1974 Edition of the ASME B&PV Code through the summer 1976 Addenda. The design of the current Westinghouse Model 44F U-tube recirculating type SGs is consistent with the original design of the RCS as well as the upper shell assemblies of the SGs which were not replaced. The PTN Units 3 and 4 SGs use drilled hole baffle plates and broached quarter foil tube support plates. The current licensing and design basis and the code requirements for the SGs are contained in UFSAR

Chapter 4. The licensee notes that the stress report for the SGs is in accordance with the 1965 ASME Code through the summer 1965 Addenda. The SG supports were designed to the requirements of the 1963 Edition of the AISC Manual of Steel Construction.

The licensee utilized a scaling factor method to evaluate the EPU effects by comparing the current and post-EPU normal and upset transient parameters to apply to the primary side and secondary side component stresses in the SG baseline analyses. The NRC staff reviewed the licensee's SG and support evaluations as presented in the EPU LR and in the licensee's responses to the staff's RAIs. The licensee used the design basis codes of record to evaluate the structural adequacy of the SGs' pressure boundary and the internal components and SG supports for the EPU conditions. The staff's review of the stress and fatigue evaluation summaries, as presented in the EPU LR Section 2.2.2.5, shows that stress ranges and fatigue CUFs are within the ASME Code, Section III, Subsection NB allowable acceptance limits. The licensee also evaluated the SG supports for EPU conditions and concluded that they meet the required design basis criteria for equipment supports. The licensee also evaluated and concluded that the EPU activities do not impact the structural integrity and the license renewal scope.

The licensee performed thermal-hydraulic analyses for bounding and nominal full power EPU conditions to demonstrate that local dryout does not occur on the tube bundle, the SGs are hydrodynamically stable, and the moisture carryover (MCO) is less than [<] 0.25 percent at EPU conditions. Local dryout in tube bundles creates the potential for enhanced deposition of corrosion products on the dry tube surface, and is avoided by assuring that the departure from nucleate boiling ratio is less than one. Hydrodynamic stability is ensured for PTN Units 3 and 4, due to the high negative value of the damping factor, indicating a stable unit where small perturbations of steam pressure or flow rate will diminish with time rather than increase in amplitude. Based on its review, the staff concludes that the thermal-hydraulic operating characteristics for the EPU are acceptable and there are no concerns of thermal-hydraulic performance deficiency, local dryout of tube walls, hydrodynamic instability or excessive moisture carryover.

The licensee's evaluations of the SG tubes for flow induced vibration (FIV) and tube wear due to higher EPU flow rates are summarized in EPU LR Section 2.2.2.5.5 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 results of the design basis evaluations were modified by the following ratios of pre-EPU and post-EPU fluid density (ρ) and velocity (v) terms. In response to staff's RAI regarding the assumptions in fluid elastic instability, turbulence, and wear, the licensee provided a supporting basis. The staff reviewed the response and agrees that these relationships are reasonable. Fluid elastic instability value at EPU = Fluid elastic instability value at pre-EPU multiplied by $[\rho v^2]_{EPU}/[\rho v^2]_{pre\text{-}EPU.}$ Turbulence displacement value at EPU = Turbulence displacement value at pre-EPU multiplied by $[\rho v^2]^2_{EPU}/[\rho v^2]^2_{pre\text{-}EPU.}$ Wear value at EPU = Wear value at pre-EPU multiplied by $[\rho v^2]^2_{EPU}/[\rho v^2]^2_{pre\text{-}EPU.}$ The licensee calculated the following values at EPU conditions, and showed that they are within the acceptable limits for PTN Units 3 and 4. Fluid elastic instability value at EPU = [[ ]] < 1.0.

In response to a RAI, the licensee provided the maximum cross flow velocity of the fluid for the tube bend region, which was calculated to be [[ ]] ft/sec. Turbulence displacement value at

EPU = [[ ]] < 89.5 mils, which is half of the gap separating the tubes based on a worst case scenario that adjacent tubes are moving 180 degrees out of phase. In the U bend region of the tube bundle, the maximum wear of tubes at EPU over the life of the plant = [[ ]] < 20 mils, where 20 mils is the plugging limit which is 40 percent of the tube wall thickness. The staff's review of the licensee's summary evaluations shows that for both units, the increase in fluid-elastic stability ratio is still less than the allowable of 1.0 at EPU conditions and is, therefore, acceptable. Hence, the staff concurs with the licensee's conclusion that the increase in the fluid-elastic stability ratio, due to the higher EPU flow rates, will not produce any significant vibration or tube wear effects. In its evaluation, the licensee showed that stress due to FIV is 450 psi and is well below the endurance limit (20000-psi at 1E11 cycles) and, therefore, the staff concurs with the licensee that fatigue due to FIV tube loadings at EPU conditions is negligible.

With regard to the SG dryer and its support structures, EPU LR Section 2.2.2.5.10 presents a steam dryer and dryer support evaluation summary for flow-induced loadings on SG internals, in accordance with the guidance of Regulatory Guide RG 1.20. This section concludes that the effects of FIV on the PTN SG dryer (secondary moisture separators) and its supports are insignificant under EPU conditions. The PTN Units 3 and 4 analysis based on RG 1.20 guidance, as it relates to PWRs, considers operating experience of the Model 44F SG two tiered steam dryers, comparative evaluations, and analytical results to develop conclusions regarding the potential adverse effects of acoustic resonances and flow induced vibrations on the SG steam dryer components. In order to evaluate the vibration potential of the PTN SG steam dryer bank assemblies, the licensee performed a finite element analysis (FEA) to determine mode shapes and frequencies. The licensee calculated the deformation, stresses, and fatigue potential resulting from dryer bank assembly vibration. Sufficient excitation originating from the acoustic loading to cause a dryer bank assembly to vibrate at the structure's natural frequencies was considered.

The analytical evaluations showed that the structural integrity of the dryer bank is maintained under such an excitation loading. In addition, the licensee, in its response to the staff's RAI, provided a justification as to why FIV and acoustic resonance, and loose parts generation are not issues with these components in PWRs at EPU conditions. The licensee indicated that industry experience of PWR SGs at roughly 28 domestic plants, operating 92 SGs with the same or similar types of dryer and support structures as those in service at PTN, Units 3 and 4, have no reported operational failures or issues related to FIV. The licensee also provided a comparison with the BWR plants, which have reported FIV-related issues in the steam dryer region. While steam flows in a BWR could reach speeds in excess of 100 ft/sec, due to redirection of flow path to the steam outlet nozzles, steam flows in the dryer region of the PWRs are very low under the EPU dryer flow conditions with a direct steam flow path to the SG steam outlet nozzle. With regard to acoustic resonance being generated at EPU flow or during power ascension to EPU power that would affect the structural integrity of the SG internals, the licensee, in its response to the staff's RAI, indicated that although there is no evidence of acoustical pressure load generation in the PTN SGs and PWRs in general, analysis has been performed to address the effects of BWR-type acoustical loadings on the PTN SG dryers for the EPU.

This analysis assumed that acoustical energy of the same general magnitude seen in the BWR industry experience is present at the SG steam outlet nozzle. The static and cyclical stresses that resulted from the potential vibration were found to be below the ASME Code allowable and

fatigue strength endurance limit of the dryer material. Therefore, the licensee concluded that, should the acoustical loadings of the magnitude observed in the BWR industry experience actually develop, the PTN SG steam dryer and support structures are found to not be susceptible to vibrational fatigue failure and loose parts generation, as a result of the EPU operating conditions.

The licensee used three different approaches to conclude that the PTN steam dryers are not susceptible to vibrational fatigue failures. In the first approach, the licensee cited PTN SG operational experience as well as other Westinghouse PWR plants with same or similar type steam dryer that showed no indication of flow or acoustic type vibrational issues. In the second approach, the licensee concluded that the geometrical differences between BWR steam dryer designs and PTN's Westinghouse Model 44F steam dryer components are very substantial so that the acoustic type vibration is unlikely to occur or inconsequential. In the third approach, the licensee performed vibration analysis and showed that the stresses in the dryer structure and attachment welds resulting from potential vibration are well below the fatigue endurance limit. The staff finds the licensees responses acceptable, as they provide reasonable assurance that there is very low potential for any impact due to flow-induced loads in the steam dryer, its support structures and adjacent area for the two PTN units, under the EPU flow conditions.

The NRC staff also notes that the licensee has a program to periodically inspect the SG upper internals in accordance with SG industry guidelines. As part of these planned inspections, the PTN SG upper internals, including the feedwater distribution system of both units, will be inspected following EPU to monitor any potential effects of increased flow. In addition, the effect of increased flow at EPU conditions will be monitored through the existing loose part monitoring procedures and in-service inspections, including periodic SG eddy current testing and foreign object search and retrieval performed during subsequent scheduled outages following EPU to ensure the integrity of safety related components. The NRC 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 also evaluated the SG supports, which includes columns, lower lateral support bumpers, and upper support bumpers for the EPU conditions, and showed that the faulted calculated loads from the RCL piping system analyses are less than the faulted allowable loads. 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, based on its review as summarized above, the NRC staff concludes that the PTN Units 3 and 4 SGs and their supports maintain their structural integrity for the effects of the proposed EPU.

Reactor Coolant Pumps and Supports

The current licensing and design basis for the reactor coolant pump (RCP) supports and pressure retaining components of the RCPs are described in Chapter 4 of the PTN UFSAR. The pressure retaining parts of the RCPs that include casings, main flanges, and main flange bolts were designed, fabricated, inspected, and tested in accordance with the ASME Code, even though the RCP is not an ASME Code pressure vessel. The licensee, in its response to the staff's RAI, indicated that the RCPs were analyzed in accordance with the design criteria from the ASME Code, Section III, 1965 Edition.

The NRC staff reviewed the licensee's RCP and supports evaluations presented in the EPU LR and in the licensee's responses to staff's RAIs. NSSS performance parameters are provided in EPU LR Tables 1-1-1 and 1.1-2, for EPU and CLTP, respectively. Only the cold leg temperatures and the cold leg transients are applicable to the RCPs, as they are located between the SG outlet and RPV inlet. The licensee performed RCP structural analysis and evaluations for those cases for which EPU inputs were not enveloped by the previously analyzed parameters. The licensee compared the design loads developed from EPU conditions to those used in the existing design basis AOR and determined that the EPU conditions are bounded by the AOR evaluations for the RCP main flange and main flange bolted joint, but not for the RCP casing.

A review of the EPU LR Table 2.2.2.6-1 shows no change in stresses and usage factors for the main flange and main flange bolted joint of the RCP. Table 2.2.2.6-1 shows a maximum increase in stresses by 3.2 percent for the RCP casing due to an increase in temperature range from 433 °F (in the original stress analysis) to EPU value of 447 °F. The staff requested that the applicant address the calculated usage factor for the pump casing. In its response, the licensee provided a revised table to include the usage factor. The stress summary shows that the stresses and fatigue usage factors for the RCP pressure retaining components for EPU conditions remained below the ASME Section III code allowable values and, therefore, are acceptable to the staff.

The licensee evaluated the RCP supports for EPU conditions and indicated that they meet the required design basis criteria for equipment support stresses. The RCP supports were designed to the 1963 Edition of the AISC Manual of Steel Construction. Table 2.2.2.6-2 contains a summary of calculated faulted loads and faulted allowable loads for the pump support members which shows that calculated loads are within the code of record allowable values and, therefore are acceptable to the staff.

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

Pressurizer and Supports

The pressurizer is a bottom-skirt supported vessel. The function of the pressurizer is to absorb any expansion or contraction of the primary coolant due to changes in temperature and/or pressure and maintain the RCS at the desired pressure. The current licensing and design basis for the pressurizer is contained in UFSAR, Chapters 4.1 and 4.3. The applicable code of record for the pressurizer is the ASME B&PV Code, Section III,1965 Edition. In considering only the effects of thermal stratification for the pressurizer surge line that connects the pressurizer nozzle to the RCS hot leg nozzle, the original code of record is the ASME Code, Section III, 1986 Edition.

The licensee evaluated the pressurizer and its supports for EPU conditions, as summarized in EPU LR Section 2.2.2.7. For the EPU NSSS design transients, the licensee's summary is provided in Section 2.2.6 of the EPU LR. 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. Hot and cold leg temperatures for EPU remain within the ranges previously considered and justified in the pressurizer stress reports. The licensee also reviewed the EPU NSSS design transients and noted that the majority of the NSSS design transients are bounded by the existing analysis with regard to the number of occurrences and severity.

The feedwater-cycling transient was added after the original analyses and, therefore, the licensee included this transient in the pressurizer's EPU evaluations. The licensee provided summary tables of stress intensities and fatigue usage factors for the various pressurizer components. In response to an RAI regarding why the usage factors for the spray nozzles, upper head, surge nozzle, and safety-relief nozzle for EPU conditions are smaller than the pre-EPU values, the license explained that the generic pre-EPU stress reports utilized design transients with numbers of cycles that envelope several plants. The EPU evaluations for PTN used plant-specific cycles instead of generic cycles, thus contributing to a lower usage factor. The staff finds this explanation satisfactory because PTN specific cycles were utilized. In addition, in an RAI, the staff requested primary plus secondary stress intensity range, simplified elastic plastic analysis multiplication factor, K_e, and thermal ratcheting check summary for the spray nozzle as these items were not included in LR Table 2.2.2.7-2 In response, the licensee provided information for the spray nozzle, and based on its review, the staff finds the information acceptable, because the licensee adequately considered the ASME Code, Class 1 requirements in establishing the structural integrity of the pressurizer spray nozzle. EPU LR Section 2.2.2.7 and the licensee's response to the staff's RAI contain stress intensity ranges and fatigue CUF summaries which meet the ASME code of record allowable values and, therefore, are acceptable to the staff.

The pressurizer support loads for EPU conditions were also evaluated by the licensee and were shown to be enveloped by the AOR loads meeting the applicable code requirements and the acceptance criteria. Therefore, the staff finds that the pressurizer supports are acceptable for EPU conditions.

Due to EPU changes to temperature and design transients, the licensee reevaluated the pressurizer surge line thermal stratification. The NRC staff's review of the pressurizer surge line thermal stratification is presented in Section 2.2.2, Nuclear Steam Supply System Piping, components, and Supports of this SE. The NRC 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 Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification."

The licensee, using the current plant design basis methodology and acceptance criteria, has evaluated the structural integrity of the pressurizer and its supports under EPU conditions. The licensee also noted in the LR that the previous evaluations for license renewal are not impacted by the EPU. Based on its review as summarized above, the NRC staff concurs with the licensee that the PTN pressurizer and its supports are structurally adequate for continued operation under the proposed power uprate.

Conclusion

The NRC staff has reviewed the licensee's structural evaluations of the pressure-retaining components and their supports. Based on its review as summarized 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. In addition, the NRC staff further concludes that the licensee has provided reasonable assurance that the pressure-retaining components and their supports are structurally adequate to perform their intended design function under EPU conditions and remain in compliance with 10 CFR 50.55a; and PTN GDCs 1, 2, and 34, 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 Reactor Pressure Vessel Internals and Core Supports

Regulatory Evaluation

Reactor pressure vessel (RPV) internals consist of all of the structural and mechanical elements inside the reactor vessel, 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 included the following: (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 acceptance criteria are based on the codes in accordance with 10 CFR 50.55a, and on GDCs specified in 10 CFR 50, Appendix A, shown below. However, because PTN is not licensed to Appendix A of GDC, the staff, in reviewing the structural integrity of SSCs for the proposed EPU, used the PTN licensed GDCs, which are shown below with a comparison of the equivalent 10 CFR 50, Appendix A GDCs. 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, "NRC Review Standard for Extended Power Uprates."

- 10 CFR 50.55a, which requires that safety-related pressure-retaining components of fluid systems meet applicable code requirements; 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.

  PTN has committed to comply with 10 CFR 50.55a.

  PTN GDC 1, requires that those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents, which

could cause undue risk to the health and safety of the public, shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary.

- GDC-2, requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions.

  PTN GDC-2, requires systems and components of reactor facilities to withstand forces imposed by extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice.

- GDC-4, requires that SSCs important to safety be designed to accommodate the effects of and be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents.

  PTN has no plant specific GDC analogous to the10 CFR 50 Appendix A GDC-4 . However, similar requirements are addressed under PTN's EQ program. UFSAR, Appendix 8A describes that equipment required to mitigate or monitor the consequences of a design basis accident must be capable of maintaining functional operability under conditions postulated to occur during its installed life as embodied in 10 CFR 50.49.

- GDC-10, requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences.

  PTN GDC-6, requires that the reactor core with its related controls and protection systems be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated.

In addition to its GDC compliance criteria, as described above, PTN pressure-retaining components and supports were evaluated for plant license renewal. The evaluations are documented in the NUREG-1759, "Safety Evaluation Report Related to the License Renewal of the Turkey Point Nuclear Plant, Units 3 and 4," dated April 2002, as supplemented in May 2002.

NRC Technical Evaluation

The evaluations for the PTN RPV core support structures (CSS) and non-CSS (all internal structures that are not CSS) for the effects of the proposed power uprate are summarized in Section 2.2.3 of the PTN EPU LR. The current licensing and design basis for the RPV internals is contained in the PTN UFSAR, Section 1.3.1, "Overall Plant Requirements"; Section 1.3.2, "Protection by Multiple Fission Product Barriers"; Section 1.9.4, "Quality Assurance Program";

Chapter 3, Section 3.1.2, "Principle Design Criteria"; and Sections 3.1.3 and 3.2.3, "Design, Fabrication, and Testing of the Reactor Vessel Internals"; and "Core Supports," respectively.

The PTN EPU LR indicates that the PTN RPV internals were designed and built prior to the implementation of Subsection NG of the ASME B&PV Code and, therefore, a plant-specific stress report on the RPV internals was not required. However, the licensee's EPU LR states that the analyses for the RPV internals have been performed that meet the intent of the ASME Code. The original analyses for the PTN reactor internals adopted the allowable stress criteria of Article 4 of the ASME B&PV Code, Section Ill, 1965 Edition through the summer 1966 Addenda. The structural integrity of the PTN reactor internals design has been ensured by analyses performed on both generic and plant-specific bases to meet the intent of the ASME Code. These analyses were used as the basis for evaluating critical PTN reactor internal components for EPU RCS conditions and revised NSSS design transients. The original Subsection NG criteria used the allowable stress levels of the 1965 Edition of the ASME B&PV Code, Section III, Article 4, through the summer 1966 Addenda.

A reactor internals generic structural and fatigue evaluation for a three-loop plant similar to PTN was performed using the rules and structural limits in the 1969 and 1971 Editions of the ASME Code, Section III, Division 1, and the criteria of the ASME Code for Design by Analysis in Section VIII, Division 2. Recent plant specific evaluations for PTN use the NRC-approved version of the ASME Boiler and Pressure Vessel Code, Section III, Division 1, Subsection NG, which is the 1998 Edition up to and including 2000 Addenda.

The NRC staff reviewed the licensee's evaluations for the RPV internals and core support structures presented in the PTN EPU LR and in the licensee's responses to the staff's RAIs. The staff noted that both generic and plant-specific structural analysis evaluations have been performed for the RPV internals that meet the intent of the ASME Code. These analyses were used as the basis for evaluating critical PTN RPV internal components for EPU RCS conditions and revised NSSS design transients. The licensee performed evaluations and assessments at the EPU conditions for the following, most critical reactor internal components: upper support plate, deep beam structure; upper core plate; upper core plate alignment pins; upper support columns; lower support plate (LSP); LSP to core barrel weld, lower core plate; lower support columns; core barrel flange and outlet nozzle; and radial keys and clevis insert assembly. A summary of the evaluations and results of the maximum stress intensity ranges and fatigue CUFs for EPU conditions compared with the current AOR are presented in the EPU LR Table 2.2.3-1**.**

The staff requested the licensee to address why some of the stress intensities and fatigue usage factors for EPU decreased significantly, in comparison with the current AOR values for the upper support columns. In its response, the licensee provided reasons, as summarized below, for the PTN upper support column (USC) stresses for the EPU condition to be lower than those documented in the current AOR. This is due to the fact that the original AOR was based on generic loads, which are conservative as compared to the PTN specific loads. Also, the AOR did not consider the wide elongated slots, while the EPU analysis considered the wide elongated slots in the USC that permit coolant flow to pass through the upper core plate (UCP) to the upper internals outlet plenum. Thus, this contributes to reduced thermal stresses. In addition, the vertical hydraulic lift loads acting on the PTN USCs for EPU are considerably lower than those in the AOR calculations, due to the fuel configuration difference between the AOR

and EPU. Further, for the AOR, the applicant used some transients that are not in the PTN design basis. Furthermore, the mechanical stresses due to seismic loadings (operating basis earthquake (OBE) and safe shutdown earthquake (SSE)) in the AOR are based on a generic design response spectra, whereas the seismic stresses calculated for the PTN EPU are based on plant-specific design response spectra. The peak seismic accelerations in the AOR are approximately five times higher than those for the PTN units. Based on the discussion above, the NRC staff finds the lower EPU results than the current AOR results acceptable.

The staff also requested the applicant to provide the primary plus secondary stress intensity ranges, including thermal bending, thermal bending stress, numerical value of the K_e factor, ratio of yield to ultimate strength, and thermal ratcheting evaluation, as applicable, for the upper core plate alignment pins, lower support plate and weld, and outlet nozzle.

In its response, the licensee provided the above requested values and corrected certain discrepancies and eliminated some conservatism in seismic loads for the upper core plate alignment pins in order to reflect more realistic EPU seismic stresses. The licensee used PTN plant-specific seismic design response spectra instead of the generic seismic design response spectra from the AOR. The staff finds the response acceptable because the licensee provided the requested additional information that adequately demonstrated that the results meet the acceptance criteria. That staff confirmed that all stresses and CUF values meet code allowable values and, therefore, are acceptable.

Based on scale model tests, as well as in-plant tests, the staff noted that the response of RPV internal components is small compared to the high cycle endurance limit of the component material. Therefore, it is concluded that fatigue due to FIV is not an issue at EPU conditions for the PTN internals.

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

Conclusion

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 and core supports, as addressed above. The NRC staff further concludes that the licensee has demonstrated that the reactor internals and core supports will continue to meet the requirements of 10 CFR 50.55a, PTN GDCs 1, 2 and 6, with respect to structural integrity following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with regards to the design of the reactor internals and core supports.

2.2.4 Safety-Related Valves and Pumps

Regulatory Evaluation

The Nuclear Regulatory Commission (NRC) staff's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME Boiler & Pressure Vessel Code (B&PV Code) and within the scope of Section XI of the ASME B&PV Code and the ASME Code for Operation and Maintenance of Nuclear Power Plants (OM Code), as applicable. The NRC staff's review focused on the effects of the proposed EPU on the required functional performance of valves and pumps at PTN Units 3 and 4. The review also covered any impacts that the proposed EPU might have on the licensee's motor-operated valve (MOV) programs related to Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance;" GL 96-05, "Periodic Verification of Design-Basis Capability of Safety-Related Motor-Operated Valves;" and GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves." The NRC staff also evaluated the licensee's consideration of lessons learned from the MOV program and the application of those lessons learned to other safety-related power operated valves. The NRC's acceptance criteria are based on (1) General Design Criterion (GDC)-1, insofar as it requires those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-37, 40, 43, and 46 insofar as they require that the emergency core cooling system, the containment heat removal system, the containment atmospheric cleanup systems, and the cooling water system, respectively, be designed to permit appropriate periodic testing to ensure the leak-tight integrity and performance of their active components; (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 program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6, and Power Uprate Review Standard RS-001.

In its LR, the licensee noted that the GDCs used during licensing of PTN predate those provided today in 10 CFR 50, Appendix A. The PTN GDCs were developed based on the 1967 Atomic Energy Commission Proposed General Design Criteria and are addressed in various sections of the Updated Final Safety Analysis Report. The following table details PTN GDCs applicable to safety-related valves and pumps that are within the scope, as stated above and its equivalent GDC from 10 CFR 50, Appendix A:

10 CFR 50 Appendix A GDC	PTN GDC
GDC-1: Quality standards and records	GDC-1: Quality standards
GDC-37: Testing of emergency core cooling system	GDC-46: Testing of emergency core cooling system components
GDC-40: Testing of containment heat removal system	GDC-59: Testing of containment pressure-reducing systems components
GDC-43: Testing of containment atmosphere cleanup systems	GDC-63: Testing of air cleanup systems components
GDC-46: Testing of cooling water system	None: Requirements are addressed in

10 CFR 50 Appendix A GDC	PTN GDC
	plant design
GDC-54: Piping systems penetrating containment	None: Requirements are addressed in plant design

NRC Technical Evaluation

In its submittal dated October 21, 2010, the licensee discussed its evaluation of safety-related valves and pumps to perform their intended functions under EPU conditions. The NRC staff has reviewed the licensee's evaluation of the impact of EPU conditions on safety-related valves and pumps at PTN.

In response to NRC Inspection and Enforcement Bulletin 85-03, GL 89-10, and GL-96-05, PTN established a testing and surveillance program for motor-operated valves (MOVs). The NRC evaluated the licensee's response to GL 89-10 and concluded on September 5, 1997 that PTN had an acceptable MOV program. GL 96-05 requested licensees to upgrade their GL 89-10 programs to include provisions to continually monitor valve performance and periodically verify MOV capability. The NRC staff concluded on June 29, 2000 that PTN had established an acceptable program to periodically verify the design basis capability of safety-related MOVs through its commitments to the Joint Owners Group Program on MOV Periodic Verification.

In its EPU license amendment request, the licensee described its evaluation of MOVs within the scope of GL 89-10 and GL 96-05 as it relates to the proposed EPU conditions. The evaluation also included a review of EPU conditions as they relate to pressure locking and thermal binding concerns as detailed in GL 95-07. The NRC staff has reviewed PTN EPU evaluation and concludes that PTN operating at EPU conditions for safety-related MOVs has a minor impact on the overall margin, and that existing MOV capability is sufficient for operation at EPU conditions. All MOVs will perform their safety-related function under EPU conditions. Therefore, all MOVs remain compliant with GL 89-10, GL 95-07, and GL 96-05.

PTN also has an air-operated valve (AOV) program. The goal of the AOV program is to enhance reliability, optimize maintenance, and provide a systematic approach to resolving AOV issues. The AOVs are evaluated based on their functions as well as normal and design basis scenarios. The AOV program has three categories which consider safety classification, safety significance, and any requirement to change position in performance of a safety-related function. The categories are:

Category 1 – AOVs that actively support a high safety significant function

Category 2 – AOVs that are safety related or quality related, low safety significant and actively support a safety related or quality related function

Category 3 – AOVs that may have special considerations as determined by PTN. Examples of these valves may be valves that have special maintenance or testing needs, whose failure may be undesirable for operation, or whose failure is of high revenue/expense significance

The licensee has evaluated all AOVs in the program for EPU conditions. The results of the evaluation show that the following valves require modifications for EPU conditions:

> Auxiliary Feedwater (AFW) System – AFW system control valves are being modified and the AFW pumps are being refurbished. This will address increasing flow requirements.
>
> Main Steam (MS) System – The MS isolation and check valves will be replaced to meet the new EPU conditions.
>
> Feedwater (FW) System – The actuators for the FW bypass flow control valves must be modified to address increased condensate pump pressures. The FW regulating valves trim are being replaced to provide increased flow capacity. New FW isolation valves are being installed and will have a requirement to close in 28 seconds.

All other Category 1 and Category 2 AOVs require no changes due to EPU conditions based on supporting calculations.

The licensee has indicated the following other valve changes are required due to the EPU:

> The inservice test (IST) program increased flow requirements will change for the AFW system pump discharge check valves, AFW pump turbine steam supply check valves, and condensate storage tank outlet check valves
>
> The setpoints for the MS safety valves will be reduced.
>
> The component cooling water (CCW) system surge tank relief valve setpoint needs to be adjusted based on the increase in peak containment pressure.
>
> Pressurizer safety valve setpoints will be reduced from 2485 psig to 2465 psig.
>
> The new FW Isolation valves installed downstream of MOV-3/4-1420 and MOV-3/4-1421 will have a requirement to close in 28 seconds. MOV-3/4-1420 and MOV-3/4-1421 will no longer have the safety requirement of closing within a specified time and can be removed from the MOV program scope of GL 89-10 and GL 96-05.
>
> The reactor coolant system (RCS) overpressure mitigating system (OMS) power operated relief valve (PORV) setpoint is to be reduced

The licensee's review of affected systems indicates that the AFW system pump flow rate requirements increase at EPU conditions and the AFW pumps are being refurbished. The licensee will evaluate changing the IST degradation curve for these pumps. For all other safety-related pumps, no changes in the pump head performance are required at the EPU conditions. Therefore, pump designs and IST program requirements for these pumps with the exception of the AFW pumps, are not affected by the EPU.

The PTN IST program will be updated to account for the EPU modifications, set point changes and component upgrades. Currently, the IST program code of record for PTN Unit 3 and Unit 4 is the 1998 Edition through 2000 Addenda of the ASME OM Code except for Mandatory

Appendix II – Check Valve Condition Monitoring Program for which the ASME OM Code 1995 Edition through 1996 Addenda is authorized.

The NRC staff reviewed the impact of EPU on safety-related pumps and valves, 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 at PTN and has determined 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 considered the lessons learned from those programs to other safety-related, power-operated valves. Based on the above described review, the NRC staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of 10 CFR 50, Appendix A criterion: GDC-1 (PTN GDC-1), GDC-37 (PTN GDC-46), GDC-40 (PTN GDC-59), GDC-43 (PTN GDC-63), GDC-46 (PTN plant design requirements), GDC-54 (PTN plant design requirements), 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 Qualifications of Mechanical/Electrical Equipment

Regulatory Evaluation

Mechanical and electrical equipment covered by this section include equipment associated with systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal. Equipment associated with systems essential to preventing significant releases of radioactive materials to the environment are also covered by this section. The NRC staff's review focused on the effects of the proposed EPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated with pipe-whip and jet impingement forces. The primary input motions, due to the SSE, are not affected by an EPU. The PTN licensed GDCs for the seismic and dynamic qualification of mechanical and electrical equipment are contained in its UFSAR, Section 1.3, and are also described in EPU LR Section 2.2.5.1. The NRC staff used the PTN licensed GDC, in reviewing the structural integrity of SSCs for the proposed EPU. Therefore, the NRC's acceptance criteria in the SE of the seismic and dynamic qualification of mechanical and electrical equipment for PTN are based on the following:

- PTN GDC-1, which requires that those systems and components of reactor facilities which are essential to the prevention or the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they

shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function, they shall be supplemented or modified as necessary;

- PTN GDC-2, which requires systems and components of reactor facilities to withstand forces imposed by extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind, or heavy ice;

- PTN GDC-40, which requires adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures;

- PTN GDC-34, which requires that the reactor coolant pressure boundary be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failures;

- 10 CFR Part 100, Appendix A, which is applicable to PTN and 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; and

- 10 CFR Part 50, Appendix B, which is applicable to PTN and which sets quality assurance requirements for safety-related equipment. Specific review guidance is contained in SRP Section 3.10 and Matrix 2 of RS-001.

NRC Technical Evaluation

The seismic and dynamic qualification of mechanical and electrical equipment for CLTP is contained in UFSAR Sections 4.1, “Reactor Coolant System, Design Basis”; 4.2, “Reactor Coolant System, RCS System Design and Operation”; 4.3, “Reactor Coolant System, System Design and Operation”; 5.1, Containment System Structure”; 5.4, “Pipe Whipping Restraints”; 6.1, “Engineered Safety Features”; and 8.1, “Seismic Qualification for Electrical Equipment”; and Appendix 5A, “Seismic Qualification of Protection System Equipment.” In addition, PTN's mechanical and electrical equipment were evaluated for continued acceptability and applicability for the plant license renewal as described in the UFSAR Chapter 16 and NUREG-1759. The licensee stated in the PTN EPU LR that the EPU will have no adverse impact on essential equipment as a result of pipe whip, jet impingement, and internal missiles.

The NRC staff reviewed the licensee’s evaluations for the seismic and dynamic evaluation of the mechanical and electrical equipment presented in EPU LR Section 2.2.5. At EPU conditions, the seismic design inputs remain unchanged. Therefore, the NRC staff concurs with the licensee that the proposed power uprate does not affect the seismic qualification of essential equipment.

The licensee’s evaluations showed that safety related equipment will continue to be protected from seismic and dynamic events and will continue to meet the PTN CLB for EPU conditions.

The licensee's evaluations also demonstrated that the dynamic qualification of equipment, components, and piping is not impacted since operating conditions such as pressure, temperature, and fluid flow do not change significantly, as a result of the EPU, except for the MS and MFW Systems. Changes in operating conditions are minor and do not impact the ability of essential safety-related equipment to withstand the effects of pipe whip, jet impingement, or internal and external missiles of equipment in close physical proximity. Based on its review, the NRC staff concludes that the current analyses are bounding under EPU conditions with the exception of the MS and MFW Systems.

For the MSS, the licensee made modifications to some of the existing pipe supports and for the feedwater system, the licensee made modifications to add HELB deflector shields at the sixth feedwater heater discharge nozzles for acceptability under EPU conditions. The staff finds that the licensees approach in that adequately modifications were made to the MS and MFW System for the EPU conditions.

In Section 2.2.1 of this SER, the NRC 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 as addressed in Section 2.2.2 shows that there is no adverse impact in the structural integrity of BOP piping, components and supports due to the dynamic effects of the EPU. The NRC staff's review of pipe rupture locations and associated dynamic effects, has determined that the licensee has adequately addressed the effects of the proposed EPU with respect to the determination of pipe rupture locations and the dynamic effects of pipe whip and jet impingement associated with the postulated rupture of piping, and that SSCs important to safety will continue to meet the requirements of PTN GDC-40, following implementation of the proposed EPU.

Conclusion

Based on a review of the licensee's evaluations regarding the effects of the proposed EPU on the qualification of mechanical and electrical equipment, the NRC staff concludes that the licensee has 1) adequately addressed the effects of the proposed EPU on these equipment, and 2) demonstrated that the equipment will continue to meet the requirements of PTN GDCs 1, 2, 14 and 40; 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 seismic and dynamic qualification of the mechanical and electrical equipment.

2.2.6 Bottom Mounted Instrumentation Guide Tubes and Flux Thimbles

Regulatory Evaluation

The bottom mounted instrumentation (BMI) system includes guide tubes, flux thimbles, and the seal table, along with the in-core detectors inserted in the flux thimbles to monitor the flux in the core, and is utilized to evaluate the core power distributions throughout core lifetime to verify that the thermal design criteria are met. The NRC's review of the BMI system mainly focused on the effects of the proposed EPU on the structural integrity of the BMI components and their continued functionality, including the capability to maintain integrity of the RCPB, and withstand

any adverse dynamic loads under the maximum temperatures and pressures associated with the proposed EPU.

The NRC's acceptance criteria for the BMI components are based on:

- 10 CFR 50.55a and GDC-1, require that safety-related SSCs be designed, fabricated, erected, constructed, tested and inspected to quality standards commensurate with the importance of the safety functions to be performed;

- GDC-2, requires that safety-related SSCs be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions;

- GDC-4, requires that safety-related SSCs be designed to accommodate and be compatible with specified environmental conditions, and be appropriately protected against dynamic effects, including the effects of missiles; and

- GDC-14, requires that the RCPB be designed, fabricated, erected and tested so as to have an extremely low probability of rapidly propagating fracture.

As noted in PTN UFSAR, Section 1.3, the GDC used during licensing of the PTN predate those currently provided in 10 CFR 50, Appendix A. The PTN GDCs were developed based on the 1967 AEC Proposed GDC and are addressed in various sections of the UFSAR.

The PTN GDC is applicable to the BMI guide tubes and flux thimbles and within the scope of the stated regulatory evaluation and are as follows:

All pressure-containing components of the Reactor Coolant System (RCS) including valves, fittings, and piping were designed, fabricated, inspected and tested in conformance with applicable codes listed in UFSAR Table 4.1-9 (e.g., ASME B&PV Code, Section III for Reactor Pressure Vessels, Steam Generators, Reactor Coolant Pumps, Pressurizers, etc., and ASA B31.1 for RCS piping, system valves and fittings). The RCS component and piping supports were designed to the requirements of the 1963 AISC Manual of Steel Construction, prior to the issuance of Subsection NF to Section III of the ASME B&PV Code. 10 CFR 50.55a was used to establish qualification boundaries for Quality Group A while Regulatory Guide (RG) 1.26 was used to establish qualification boundaries for Quality Groups B, C, & D. Conformance with specific requirements of 10 CFR 50.55a is delineated in the FPL Quality Assurance Topical Report.

> PTN GDC-1, "Quality Standards":
>
> Those systems and components of reactor facilities which are essential to the prevention, or the mitigation of the consequences, of nuclear accidents which could cause undue risk to the health and safety of the public shall be identified and then designed, fabricated, and erected to quality standards that reflect the importance of the safety function to be performed. Where generally recognized codes and standards pertaining to design, materials, fabrication, and inspection are used, they shall be identified. Where adherence to such codes or standards does not suffice to assure a quality product in keeping with the safety function,

> they shall be supplemented or modified as necessary. Quality assurance programs, test procedures, and inspection acceptance criteria to be used shall be identified. An indication of the applicability of codes, standards, quality assurance programs, test procedures, and inspection acceptance criteria used is required. Where such items are not covered by applicable codes and standards, a showing of adequacy is required.

As described in the PTN UFSAR, Sections 3.2.3 and 7.6.2, the BMI penetrates the reactor vessel lower head. The 50 bottom head instrumentation tubes and attached bottom mounted guide tubes, flux thimble tubes, and seal table for each reactor vessel provide capability of monitoring core flux distribution. Conduits extend from the bottom of the reactor vessel down through the concrete shield area and up to a thimble seal table. The flux thimble tubes are closed at the leading ends and serve as the pressure barrier between the reactor pressurized water and the containment atmosphere. The mechanical seals between the retractable thimbles and the surrounding conduits are provided at the seal table. The instrumentation guide tubes running through the center of the fuel assemblies and the in-core instrumentation support structure are considered part of the reactor vessel internals, while the conduits and thimble tubes as pressure-containing components are considered part of the extended RCPB.

As described in the PTN UFSAR, Section 4.1.2, the RCS is of primary importance with respect to its safety function in protecting the health and safety of the public. Quality standards of material selection, design, fabrication and inspection conform to the applicable provisions of recognized codes and good nuclear practice are listed in UFSAR, Section 4.1.7. Details of the quality assurance programs, test procedures and inspection acceptance levels are given in UFSAR Sections 1.9, 4.4, and Table 4.4-1. Particular emphasis is placed on the assurance of quality of the reactor vessel to obtain material whose properties are uniformly within tolerances appropriate to the application of the design methods of the code.

> PTN GDC-2, “Performance Standards”:
>
> Those systems and components of reactor facilities which are essential to the prevention or to the mitigation of the consequences of nuclear accidents which could cause undue risk to the health and safety of the public shall be designed, fabricated, and erected to performance standards that will enable such systems and components to withstand, without undue risk to the health and safety of the public, the forces that might reasonably be imposed by the occurrence of an extraordinary natural phenomenon such as earthquake, tornado, flooding condition, high wind or heavy ice. The design bases so established shall reflect: (a) appropriate consideration of the most severe of these natural phenomena that have been officially recorded for the site and the surrounding area and (b) an appropriate margin for withstanding forces greater than those recorded to reflect uncertainties about the historical data and their suitability as a basis for design.

As described in UFSAR, section 3.2.3, the reactor internals are equipped with bottom-mounted in-core instrumentation supports which are designed to withstand the forces due to weight, preload of fuel assemblies, control rod dynamic loading, vibration, and LOCA blowdown coincident with earthquake acceleration. As described in the PTN UFSAR, Section 4.1.2 and the PTN UFSAR, Appendix 5A-1.2, all piping, components and supporting structures of the RCS

(including BMI guide tubes and flux thimbles) are designed to Seismic Class I requirements; i.e., they are capable of withstanding: (a) the design seismic ground acceleration within code allowable working stresses; and (b) the maximum potential seismic ground acceleration acting in the horizontal and vertical direction simultaneously with no loss of capability to perform their safety function. The PTN UFSAR, Appendix 5A-1.3.2 provides further detail. The RCS is located in the containment building whose design, in addition to being a Class I structure, considers accidents or other applicable natural phenomena. The PTN UFSAR, Section 5 also provides further detail.

PTN does not have a plant-specific GDC analogous to 10 CFR 50, Appendix A, GDC-4, which requires that SSCs important to safety be designed to accommodate the effects of and be compatible with environmental conditions associated with normal operation, maintenance, testing, and postulated accidents. However, such requirements are addressed under PTN's EQ program as addressed below.

As described in UFSAR Appendix 8A, equipment required to mitigate or monitor the consequences of a design basis accident must be capable of maintaining functional operability under conditions postulated to occur during its installed life. This design requirement is embodied in 10 CFR 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants." When the plant's construction permits were issued, EQ was performed on a generic basis in documents such as WCAP [Westinghouse Commercial Atomic Power] and in the normal design and procurement of equipment required for safety. Safety related capability was assured by a conservative design.

Wherever possible, all active components required for SSD of the plant were located outside containment and away from post accident harsh environments. PTN's EQ program developed and maintains a list of equipment consistent with the criteria established in 10 CFR 50.49, i.e., safety-related electrical equipment that is relied upon to remain functional during and following design basis events, and nonsafety electric equipment whose failure under postulated environmental conditions could prevent satisfactory accomplishment of safety functions.

> PTN GDC-40, "Missile Protection":
>
> Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures other than a rupture of the Reactor Coolant System piping.

As described in the PTN UFSAR, Appendix 5A, all piping, components and supporting structures of the RCS (including BMI guide tubes and flux thimbles) are designed to Seismic Class I requirements. As described in the PTN UFSAR, Appendix 5E, the reactor vessel and all reactor coolant loop components are enclosed by the containment structure which is designed to withstand the impact of all external missiles. The BMI guide tubes and flux thimbles are either contained within the reactor pressure vessels or within the reactor cavity below them and protected from potential internal missiles by the primary shield wall, reactor cavity walls, and the operating floor slab above.

PTN GDC-34, "Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention":

The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failure. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes.

The BMI guide tubes and flux thimbles were evaluated for plant license renewal. The results are documented in UFSAR, Section 16, "Aging Management Programs and Time-Limited Aging Analyses Activities," and in NUREG-1759.

NRC Technical Evaluation

The BMI system consists of neutron flux detectors, flux thimbles, and the flux thimble guide tubes. The thimbles and guide tubes provide a pathway through which the flux detectors can be inserted into the reactor core during operation. The BMI flux thimble guide tubes from the weld at the bottom of the reactor pressure vessel (RPV) head to the seal table are analyzed and evaluated for acceptance to EPU design parameter conditions. There are a total of 50 BMI guide tubes running from the weld at the RPV bottom head to the seal table, resulting in many different tubing lengths. The licensee selected three representative tubes and performed the evaluation and analysis in order to encompass the different tubing lengths. The guide tubes are internally pressurized to the reactor coolant loop (RCL) pressure. The BMI guide tubes are analyzed and evaluated for deadweight, thermal, seismic, and LOCA loading conditions. The guide tubes are analyzed and evaluated for acceptance in accordance with the requirements of ASME B&PV Code, Section III, 1989 Edition. The BMI thimble tubes are one inch in diameter, and per NB-3630, the tubes may be qualified to the criteria requirements of Subsection NC of the ASME Code. The licensee reconciled the ASME Code with B31.1. The EPU structural analysis of the BMI flux thimble guide tubing was performed by the licensee using the piping analysis program WESTDYN and was shown to be acceptable for EPU conditions.

The staff reviewed the maximum BMI tubing stresses tabulated in LR Table 2.2.7-1 and finds the results to be acceptable because they are in compliance with the code criteria requirements. The BMI thimble guide tubing support loads from the BMI guide tubing analysis for deadweight, thermal, seismic, and LOCA loading cases are evaluated by the licensee for acceptability to the applicable code requirements. The loads at the interface location of the BMI tubing and the seal table, as well as the RPV connections from the BMI tubing analysis were used by the licensee for qualification and are found acceptable because they are consistent with the applicable code requirements.

In response to the staff's request regarding the 2-inch interface for temperature change from 547 °F to 120 °F, the licensee provided justification that the un-insulated BMI tubes are considered at 120 °F and the first 2-inch length nozzle portion from the RPV bottom essentially

covered by the insulation is considered at RPV temperature of 547 °F. The staff finds the above justification reasonable because of the insulation effect. The licensee also provided clarification to the staff's request on the allowable stress criteria used for the BMI tubing stress qualification, which is in accordance with the ASME B&PV Code, Section III, Subsection NC. Furthermore, the licensee added this clarification to the BMI tubing stress qualification in Table 2.2.7-1 and, therefore, the staff finds this acceptable.

The BMI guide tubing supports are classified as ASME Code, Class 2 linear type supports. They were analyzed and evaluated for the EPU conditions by the licensee and were shown to be acceptable in meeting the requirements of ASME B&PV Code, Section III, Division 1, Subsection NF, 1998 Edition. In response to the staff's RAI to provide a summary of the results of the BMI guide tubing support qualification, the licensee provided a summary of the maximum stresses the BMI tubing supports along with the allowable stresses, and load combinations. The staff reviewed the BMI tubing support qualification summary, and finds it acceptable because the results meet the applicable code criteria for Class 2 NF supports.

Conclusion

The staff reviewed the evaluations performed by the licensee for the BMI tubing system and its supports for the effects of the proposed EPU. Based on its review, the staff concludes that the licensee has adequately accounted for the effects of changes in plant conditions associated with the proposed EPU on the design of the BMI tubing system and that the BMI tubing system will maintain its structural integrity under the operating conditions of the proposed EPU. The staff further concludes that the BMI tubing system will continue to meet the requirements of its current licensing basis with regard to 10 CFR 50.55a and PTN GDCs 1, 2, 34, and 40. Therefore, the staff finds the BMI system acceptable for the proposed EPU conditions.

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 which could result from design basis accidents (DBAs). Electrical equipment important to safety is described in Title 10 of the *Code of Federal Regulations* (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 Nuclear Regulatory Commission (NRC) staff's review focused on the effects of the proposed extended power uprate (EPU) on the environmental conditions that the electrical equipment will be exposed to during normal operation, anticipated operational occurrences, and accidents. 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 EQ of electrical equipment important to safety that is

located in a harsh environment. Specific review criteria are contained in NRC's Standard Review Plan (SRP) Section 3.11.

NRC Technical Evaluation

Inside Containment

The EQ for electrical equipment located inside containment is based on a main steamline break (MSLB) and loss of coolant accident (LOCA), and evaluation of resultant temperature, pressure, humidity, chemistry exposure (e.g., pH), and radiation consequences. The EQ also includes the environment expected to exist during normal plant operation. The licensee stated that the EQ of electrical equipment at PTN Units 3 and 4 is based on the Division of Operating Reactors Guidelines or NUREG-0588 criteria. According to the licensee, any component replaced after February 22, 1983, is qualified to NUREG-0588 Category I (i.e., qualified to the Institute of Electrical and Electronics Engineers Standard 323 dated 1974 (IEEE Std. 323-1974)). The NRC staff's review verified that the normal operating conditions such as temperature, pressure, humidity, pH, submergence, and radiation, at EPU, continue to be bounded by the existing EQ analyses. Further, the staff reviewed to assess whether the post-accident temperature, pressure, humidity, pH, submergence also continue to be bounded by the existing EQ analyses.

During its review, the staff observed that some EPU post-accident pressure points, after peak of the EPU pressure profile, slightly exceed the current EQ envelope during the Post Accident Operability Time (PAOT) period of 31 days. In response to the staff's request for additional information as to how the margins identified in the IEEE Std. 323-1974 for temperature, pressure, etc., are being maintained under EPU conditions, the licensee provided the following clarification in a letter dated March 31, 2011:[28]

> The EQ program licensing basis is based on IEEE 323-1971 which does not require margins above the design basis accident profiles. The licensee is committed to meet NUREG-0588, "Interim Staff Position on Equipment Qualification of Safety-Related Electrical Equipment," and the later version of IEEE 323-1974 for any EQ equipment installed after February 22, 1983, as part of the original NRC program approval.
>
> Regarding radiation margin, the licensee stated that it used methods to determine the radiation parameters consistent with the Appendix D methodology of NUREG-0588. In accordance with Item 1.4 of NUREG-0588, additional margin need not be added if the methods identified in Appendix D of NUREG-0588 are utilized.
>
> Regarding temperature margin, the licensee stated that the EPU LOCA temperature curve does not drop below a 15 °F [degrees Fahrenheit] margin until after at least 2.7 hours when the temperature is declining. In addition, the temperature steps shown on the EQ Envelope show higher temperature maintained for significantly longer than the EPU LOCA temperature curve. This adds to the margin since electrical equipment aging is a function of temperature

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> and duration. Therefore, the margin added due to maintaining a longer duration at higher temperatures is considered adequate for qualification.
>
> Regarding pressure margin, the licensee stated that the EPU pressure design curve does not drop below 10% [percent] margin until after at least 50 minutes at which time both the design and EQ curves decrease by at least 20 psi. The first time step, which is at the highest pressure, provides greater than 10% margin. The remaining time steps maintain the EQ profile at constant pressure above the design profile for the majority of the time that compensates for the subsequent time steps where the 10% margin is not achieved. The damage mechanism associated with pressure is not age-related, but a function of the pressure magnitude which can cause greater moisture intrusion. Since the EQ profile maintains the pressure above the design profile for a greater duration and the maximum pressure is above 10% of design, the developed margin is considered adequate for qualification.

Since the licensee considered methods for radiation parameters in accordance with NUREG-0588, Appendix D, the staff finds that no additional radiation margin is required. The staff also finds that adequate margins for temperatures and pressures exist at the peak of EPU LOCA profiles. Furthermore, the EQ program licensing basis for PTN Units 3 and 4 is based on IEEE Std. 323-1971 which did not require any specific margins for temperatures and pressures above the design basis accident profiles, based on this information the staff considers the available margins acceptable for equipment qualified in accordance with IEEE Std. 323-1971. The licensee is committed to maintain margins for any EQ equipment installed after February 22, 1983, consistent with the criteria specified in IEEE Std. 323-1974 in order to meet the intent of 10 CFR 50.49.

The licensee in its letter dated March 31, 2011, clarified that the EPU maximum containment flood level is 2.2 inches higher than the pre-EPU flood level. Based on its review of EQ documentation packages for equipment inside containment and other configuration control documents, the licensee determined that no EQ equipment is located below the flood level. Based on this information, the staff has no concerns with submergence of EQ equipment under EPU conditions.

The radiation for safety-related electrical equipment inside containment is based on the radiation environment expected to exist during normal operations, post-LOCA conditions, and the resultant cumulative radiation doses. For any containment EQ equipment that could not meet the new EPU bounding radiation dose level, the licensee assessed the dose reduction of the equipment based on whether the equipment was sealed, shielded or based on actual distance from the source. The licensee stated that based on the dose reduction, the EPU accident radiation dose for all EQ equipment was found to be below the existing equipment qualification levels.

By letter dated March 31, 2011, the licensee clarified that corresponding to EPU conditions, in-containment gamma radiation exceeded EQ requirements for 18 Rosemount transmitters (nine in PTN Unit 3, and nine in PTN Unit 4). The licensee developed location-specific integrated gamma dose estimates for these transmitters. Since these transmitters are sealed, exposure to in-containment beta radiation was not a concern. The licensee stated that based on generic

guidance provided in NRC IE Bulletin 79-01B, the contribution of beta radiation can be ignored if the radiation sensitive portion of the component is sealed in an enclosure. The licensee developed location-specific gamma dose to each of the 18 transmitters while considering the shielding provided by major walls and floors within the containment. Based on its location-specific calculation, the licensee stated that the results of adding the 31-day integrated post-LOCA to the 60-year normal operation dose for the 18 Rosemount transmitters shows that these transmitters will remain below the radiation dose qualification level under EPU conditions. Based on its review, the staff finds that beta radiation doses can be ignored because the approach is consistent with the guidance provided in NRC IE Bulletin 79-01B and since beta radiation can be blocked by a thin metal layer, and the gamma dose reduction effect by major walls and floors within the containment can be considered in the gamma dose calculations.

By letter dated July 7, 2011, the licensee provided a summary of radiation doses for electrical equipment for the Pre-EPU and EPU conditions. Based on the above and our review of the LAR and supplemental responses dated March 31, 2011, July 7, 2011, and July 22, 2011, the staff finds that the EQ of electrical equipment will remain bounding under EPU conditions inside containment.

Outside Containment in Auxiliary Building

The EQ for electrical equipment located outside containment in the auxiliary building is based on design basis high-energy line breaks (HELBs) and the resultant temperature, pressure, humidity, and radiation consequences. The EQ also includes the environment expected to exist during normal plant operation. The staff reviewed the licensee's EQ evaluation contained in the EPU application for outside containment in the auxiliary building. The staff's review verified that the normal operating conditions such as temperature, pressure, humidity, pH, and radiation, at EPU, continue to be bounded by the existing EQ analyses. The staff reviewed the LAR to assess whether the existing analyses for EQ equipment also bound EPU conditions of temperature, pressure, humidity, flooding, and pH, resulting from HELB in the auxiliary building.

The licensee noted that some areas in the auxiliary building become harsh due to a radiation dose increase under EPU accident conditions. The licensee assessed the dose reduction for any auxiliary building EQ equipment that could not meet the new EPU bounding dose. Factors for dose reduction included equipment shielding, and actual distance from the radiation source. Based on the dose reduction, the licensee found the EPU dose for all EQ equipment to be below the existing equipment qualification levels.

In response to a staff RAI, the licensee clarified in its letter dated March 31, 2011, that five components outside containment required further evaluation due to radiation dose increase under EPU accident conditions. These components included: (1) cables manufactured by Okonite; (2) cables manufactured by General Cable; (3) cables manufactured by Kerite; (4) Masoneilan I/P transducers; and (5) Valcor solenoid valves. The licensee stated that for cables manufactured by Okonite and General Cable, the location specific dose calculations showed that the dose outside containment was below the qualification levels for these cables; and qualification of EQ cables manufactured by Kerite was demonstrated by a new EQ test report that enveloped the EPU higher dose. Regarding the Masoneilan I/P transducers and Valcor solenoid valves, the licensee stated that these are part of the post accident sampling system (PASS), and these PASS equipment are determined as not required to mitigate an

accident or provide operator assessment capability, and will be removed from EQ master list. The licensee also confirmed that no new equipment is required to be added to the PTN EQ List as a result of the reviews performed for EPU.

By letter dated July 7, 2011, the licensee provided summary of radiation doses for electrical equipment for the Pre-EPU and EPU conditions. Based on our review of the LAR and supplemental responses dated March 31, 2011, and July 7, 2011, the staff finds that the licensee has adequately addressed the effect of EPU on EQ equipment and that the EQ of electrical equipment will remain bounding under EPU conditions outside containment in the auxiliary building.

Outside Containment – Main Steam Trestle Area

The safety-related equipment located in the main steam trestle area have safety functions to mitigate the consequences of feedwater line breaks or MSLB. The licensee provided summary of evaluation of EQ under EPU conditions for normal and accident conditions, in the trestle area. Based on our review of this summary, the staff finds that the EQ of equipment in the main steam trestle area will remain bounding under EPU conditions.

License Renewal Impact Evaluation

In the LAR and supplemental response dated March 31, 2011, the licensee stated that no new aging effects have been identified for equipment in the EQ program as a result of EPU. The staff reviewed the licensee's EQ program, as described in the PTN Units 3 and 4 Updated Final Safety Analysis Report (UFSAR) Chapter 16.2.6, and finds that the EQ program will continue to cover the scope of aging management during the license renewal period with no impact due to the EPU conditions.

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 EQ of electrical equipment inside and outside containment. The NRC staff further concludes that the electrical equipment will continue to meet the relevant requirements of 10 CFR 50.49 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EQ of electrical equipment.

2.3.2 Offsite Power

Regulatory Evaluation

The PTN Units 3 and 4 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 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 increasing the probability for losing offsite power to the plant following implementation of the proposed EPU. The NRC's acceptance

criteria for offsite power systems are based on General Design Criterion (GDC) 17. The applicable principal design criteria for PTN predate this criterion.

The PTN principal design criteria for electric systems is described in UFSAR Section 8.1.1. The emergency power for engineered safety features of PTN was designed prior to the implementation of 10 CFR 50, Appendix A, “General Design Criteria for Nuclear Power Plants.” The electrical power systems for PTN Units 3 and 4 were designed in accordance with the Atomic Energy Commission’s (AEC) draft design criterion. PTN Units 3 and 4 GDC 39, “Emergency Power for Engineered Safety Features,” is applicable for the design of the site electric power systems and mirrors the draft AEC design criterion for emergency power for Engineered Safety Features. Subsequently, the AEC draft design criterion for emergency power for Engineered Safety Features was implemented in 1971 as GDC 17, “Electric power systems,” which established more specific requirements than previously identified. The licensee performed an evaluation of the site electrical system design in 1982 and concluded that PTN complies with the requirements of GDC 17.

PTN Units 3 and 4 GDC 39 requires that alternate power systems shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite power system and the offsite power system shall each, independently, provide this capacity assuming a failure of a single active component in each system.

The specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to SRP Section 8.2, and Branch Technical Positions (BTPs) PSB-1 and ICSB-11.

NRC Technical Evaluation

At PTN, independent alternate power systems are provided for each unit, with adequate capacity to supply the power required for engineered safety features and protection systems. For each unit, the source of auxiliary power during normal operation is the main generator and switchyard. During normal operation, the unit auxiliary transformer (UAT) supplies power to safety-related 4.16 kilovolt (kV) buses A and B. Nonsafety-related bus C is supplied by C-transformer which is connected to the 240 kV switchyard. In the event of turbine trips, an automatic transfer connects the 4.16 kV buses A and B to the startup transformer. The startup transformer for each nuclear unit can also provide redundant offsite power to the 4.16 kV bus A of the other unit.

In the event both PTN units are inoperative, offsite power is available from the 240 kV switchyard from the Turkey Point fossil fuel fired generators or from one of the 240 kV transmission lines. The main generator for each unit is directly connected through a 22 kV isolated phase bus to the main transformer (MT). The high voltage side of MT is connected to the 240 kV switchyard through overhead tie-lines.

The offsite transmission system is designed to:

- Accept electrical output of the plant.
- Supply offsite power to the plant 4 kV safety-related buses during unit startup, shutdown, and after reactor trip or at any time that auxiliary power is unavailable from UAT.
- Provide power to the nonsafety C-Bus system during unit startup, normal, and shutdown operation.

The staff evaluated the offsite power system and its components to ensure that they are capable of performing their intended function at EPU conditions. Our evaluation is based on the system's required design function and comparison between the equipment ratings and the anticipated operating requirements at EPU conditions. The staff also reviewed the grid stability study corresponding to the EPU conditions. The staff's evaluation of the offsite power system is as follows:

Grid Stability

In its letter dated October 29, 2010, the licensee provided a copy of the System Impact Study which evaluated the impact of the increased power output (approximately 15 percent that includes a 13 percent power uprate and a 1.7 percent measurement uncertainty recapture (MUR) of PTN Units 3 and 4 on the FPL transmission system. The performance of the System Impact Study included reactive power capability analysis, short circuit analysis, and dynamic stability analysis.

Based on the reactive capability analysis, each unit's increased turbine-generator capability met the reactive capability requirements of the transmission system under EPU conditions.

The fault level at the 240 kV switchyard increased to within 200 Amperes (A) of 63 kA short circuit rating of several 240 kV breakers at Turkey Point corresponding to PTN Unit 4 EPU conditions. The licensee proposed installing two new 5 ohm inductors in the switchyard to reduce the available fault levels. According to the licensee, this modification will provide a minimum margin of 500 A.

Based on the dynamic stability analysis, power system stabilizers will be required for PTN Units 3 and 4 to improve oscillations damping. The analysis also recommended the reduction of the existing Breaker Failure Backup total clearing time at Flagami and Davis susbstations.

The System Impact Study, provided in the letter dated October 29, 2010, considered a maximum of 889 Megawatts Electric (MWe) generation of each unit. In response to a staff RAI, the licensee in its letter dated March 31, 2011, provided an Addendum to the System Impact Study with a maximum of 899.8 MWe generation for each unit. The licensee stated that a subsequent heat balance performed after the original System Impact Study specified an EPU peak winter power level of 898.9 MWe under more stringent winter cooling water temperature assumptions. This Addendum to the System Impact Study addressed the impacts of using a more conservative power level of 899.8 MWe. No additional transmission reinforcements were identified by the licensee as a result of the higher generator output.

The staff reviewed the System Impact Study and its Addendum, and concludes that the impact of PTN operation under EPU conditions on grid stability has been adequately studied and analyzed.

Switchyard Components

At EPU conditions, the licensee concluded that all 240 kV circuit breakers in the switchyard will be within their ratings under EPU conditions (after installation of the 5 ohm inductors discussed above under grid stability). The licensee stated that corresponding to EPU conditions, the 240 kV disconnect switches associated with MT tie lines and Bays 7 and 9 associated with the 240 kV buses and transmission line circuit breakers will be replaced with 3000 amperes (A) ratings.

The licensee also concluded that all multi-ratio current transformers in all circuit breakers in Bays 7 and 9 will need adjustment from 2000/5 A ratio to 3000/5 A to accommodate the increased unit outputs under EPU conditions. Accordingly, appropriate meter scales and relay setpoints will be changed and adjusted. Based on its review, the staff finds the modified/upgraded switchyard component ratings to be consistent with the EPU conditions.

The staff, in general, has considered components such as the main generator, the UAT, the startup transformer, and other power supply systems/components upstream of safety-related buses as part of ac offsite power.

Main Generator

The existing TPN Units 3 and 4 main generator rating is 894 megavolt amperes (MVA) at 0.85 power factor. The licensee stated that the existing generators will be modified to deliver a maximum real power output of 899.8 MWe under EPU conditions. The modified generators will have a rating of 1032 MVA at 0.85 power factor. The size of upgraded generators will support operation at EPU conditions corresponding to 899.8 MWe generation including the machine reactive power requirements of 0 to 375 megavolt amperes reactive. The licensee stated that the main generators will be upgraded prior to implementing the EPU.

In the LAR, the licensee stated that the existing current transformers of the main generators will be replaced and the existing main generator protection relay settings will be revised as part of the plant modification process prior to implementing the EPU. In response to a staff RAI, the licensee in its letter dated March 31, 2011, stated that the existing current transformer ratings are 30,000 A and the replacement current transformer ratings will be 35,000 A. The licensee also stated that to accommodate the change in capacitance of the modified generator, the generator neutral grounding transformer and resistor will be replaced. No other major changes, such as protective relay replacements, are required.

Based on its review, the staff finds that the uprated size of the main generator will be adequate to support safe operation under EPU conditions.

Isolated Phase Bus Duct

The licensee determined that based on the upgraded main generator rating of 1032 MVA, the existing isolated phase bus duct (IPBD) will need replacement with a new main bus with larger conductors and enclosures, using the existing cooling system to support unit operation at EPU conditions. The licensee stated that the new IPBD rating will bound the 28,508 A requirement corresponding to EPU conditions. The IPBD will be replaced as part of the modification process prior to EPU.

In response to a staff RAI in letter dated July 7, 2011, the licensee confirmed that the new IPBD is rated for 28,508 A for EPU conditions. Based on its review, the staff finds that an upgraded IPBD rating of 28,508 A will be adequate to support safe operation under EPU conditions.

Main Transformers

In the LAR, the licensee stated that the existing MT rating of 850 MVA will be upgraded to 970 MVA to support unit operation at EPU conditions, by providing a new cooling system. The upgraded transformer capacity modifications will be implemented as part of the modification process for each unit prior to EPU. Based on its review, the staff finds that main transformer rating of 970 MVA will be adequate to support safe operation under EPU conditions.

Unit Auxiliary Transformers

In the LAR, the licensee stated that the existing three-winding UATs with a design rating of 50/25/25 MVA will be replaced with new UATs with a similar rating due to degradation. The licensee determined that the rating will remain adequate to support each unit operation at EPU conditions.

Based on its review, the staff finds that the UAT rating, as indicated above, will be adequate to support safe operation under EPU conditions based on loading of UATs provided in Table 2.3.3-4 of the LAR.

Startup and C-Bus Transformer

The licensee determined that the existing rating of the startup transformers (33.6/44.8 MVA) and C-Bus transformers (30/40/50 MVA) will remain adequate to support each unit operation at EPU conditions.

Based on its review, the staff finds that the startup and C-Bus transformer ratings, as indicated above, will be adequate to support safe operation under EPU conditions based on loadings of these provided in Tables 2.3.3-5 and 2.3.3-6 of the LAR.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the offsite power system and concludes that with the proposed modifications discussed in this section, the offsite power system will continue to meet PTN GDC 39 following implementation of

the proposed EPU. The staff also finds that the offsite power system has the capacity and capability to supply power to all safety loads and other required equipment.

The NRC staff further concludes that the impact of the proposed EPU on grid stability will be negligible after modifications in the offsite system discussed in Section 2.3.2 are implemented. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the offsite power system.

2.3.3 Alternating Current Onsite Power System

Regulatory Evaluation

The alternating current (ac) onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to safety-related equipment. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the ac onsite 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 anticipated operational occurrences and accident conditions.

The applicable principal design criteria for PTN predate this criterion. The PTN principal design criteria for electric systems is described in UFSAR Section 8.1.1. The emergency power for engineered safety features of PTN Units 3 and 4 was designed prior to the implementation of 10 CFR 50, Appendix A. The electrical power systems for PTN Units 3 and 4 were designed in accordance with the AEC's draft design criterion. PTN GDC 39, "Emergency Power for Engineered Safety Features," is applicable for the design of the site electric power systems and mirrors the draft AEC design criterion for emergency power for engineered safety features. Subsequently, the AEC draft design criterion for emergency power for engineered safety features was implemented in 1971 as GDC 17, "Electric power systems," which established more specific requirements than previously identified. The licensee performed an evaluation of the site electrical system design in 1982 and concluded that PTN complies with the requirements of GDC 17.

PTN GDC 39 requires that alternate power systems shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite power system and the offsite power system shall each, independently, provide this capacity assuming a failure of a single active component in each system.

Specific review criteria are contained in SRP Sections 8.1 and 8.3.1.

NRC Technical Evaluation

The NRC staff reviewed the licensee's submittal to determine whether the plant onsite ac distribution system consisting of the 4.16 kV system, the 480 V system, the emergency diesel generators (EDGs), and the 120 Volt (V) and 120V/208V systems would remain capable of performing their intended functions at EPU conditions. These power systems provide power to

essential ac loads including adequate protection and control during normal and design basis events.

4.16 kV System

The onsite ac power system is described in UFSAR Section 8.2.2.1.

According to the licensee, the 4.16 kV system loads that will be increased as a result of EPU are the steam generator feedwater pump, the condensate pump, the heater drain pump, the intake cooling water pump, and the circulating water pump motors. The licensee stated that EPU operation will result in a minor reduction in reactor coolant pump (RCP) motor brake horsepower (BHP) demand due to a decrease in flow resistance. However, a change in calculation methodology by the OEM [original equipment manufacturer] has resulted in a newly understood higher hot loop running BHP for the RCPs under current plant conditions. As noted in Table 2.3.3-15 of the LAR, the various motor BHP load requirements remain within nameplate ratings, except for condensate pump and circulating water pump motors. The licensee is having the condensate pump motors rewound to increase the motor nameplate rating to support EPU conditions. EPU has minimal impact on circulating water pump motors which exceeds the motor nameplate rating, but operates within motor service factor. The staff considers the operation of circulating water pump motors at exceeding nameplate rating but within motor service factor (also sometimes referred as safety factor) as acceptable based on general industry practice.

According to the licensee, the maximum momentary short circuit currents slightly exceed switchgear bus ratings at 4.16 kV Buses 3AA1 and 3AB1 for existing conditions and at buses 4AA1 and 4AB1 for both existing and EPU conditions. The licensee stated that this is considered acceptable based on very low likelihood of occurrence and very low level of consequence rationales. There is no impact on other 4.16 kV switchgear ratings as a result of EPU. In response to a staff RAI, the licensee in its letter dated March 31, 2011, stated that the electrical analysis which was originally presented in the EPU LAR has been updated to reflect actual UAT vendor test data. The new test data is the result of the plan to replace the UATs for non-EPU related reasons. The new UAT test data results in buses 4AA1 and 4AB1 having a momentary overload [overduty] under EPU conditions. This condition is eliminated for buses 3AA1 and 3AB1 under EPU conditions. The condition is decreased in severity for buses 4AA1 and 4AB1 under EPU conditions. Also, the RCP and steam generator feed pump circuit breakers on bus 4AA1 have an interrupting short circuit current overduty under both existing and EPU conditions and the RCP circuit breakers on bus 4AB1 has an interrupting short circuit current overduty under pre-EPU conditions. In the post-EPU state the bus 4AB1 overduty conditions are eliminated.

The licensee provided a number of rationales for the overduty conditions described above. The most significant rationale which is considered acceptable by the staff is as follows: The bus overduty condition only exists when the associated EDG is paralleled to the grid through the UAT. This condition occurs only during EDG testing which is one hour per month and 24 hours every 18 months. The licensee declares the EDG inoperable when paralleled to the grid. The interrupting ratings are adequate when the EDG is not paralleled to the grid. According to the PTN UFSAR, if an EDG is in test mode and paralleled to the offsite power and an safety-injection-signal is initiated, the EDG breaker will trip, the EDG will continue to run and vital loads

required for emergency shutdown will be sequentially loaded to the bus by the sequencer, with the power being supplied from the offsite power source. Therefore, EDG will not run in parallel with offsite power during an accident. The 4.16 kV breaker interrupting ratings remain adequate during accident and nonaccident conditions when an EDG is not paralled with the offsite power. The staff finds this rationale acceptable for the adequacy of existing interrupting rating of breakers.

Based on transient and steady state voltage analysis, the licensee determined that there are no adverse effects on the loss of voltage relays and reactor protection system reactor trip undervoltage relays at 4.16 kV voltage level. Based on its review, the staff finds the licensee's assessment adequate, since there is minimal impact on the 4.16 kV voltage buses under EPU conditions, as noted in Table 2.3.3-14 of the LAR.

480 V System

The 480 V system is described in PTN UFSAR Section 8.2.2.1.1. The licensee determined that although certain 480 V loads will change under EPU conditions, all 480 V electrical distribution equipment ratings remain adequate.

The licensee's evaluations determined that there are no adverse voltage effects on the safety-related 480 V load centers protected by degraded voltage relays and undervoltage relays. The minimum steady-state voltage and transient-state voltages on the safety-related 480 V load centers and motor control centers remain above the allowable design values. Therefore, the degraded voltage relay and undervoltage relay settings are not affected by operation at EPU conditions. The licensee proposed reducing voltage tolerance band (from ±5V to ±3V) of degraded voltage and undervoltage relay settings in the Technical Specifications in order to increase margin for any future 480 V system load growth, although no setpoint changes were required as a result of the EPU.

Based on the staff's RAI, the licensee in its letter dated March 31, 2011, provided summary of analyses of the degraded voltage and undervoltage relays settings under EPU conditions. Based on its review of the summary of the analyses provided by the licensee, the staff finds that there is minimal impact on the 480 V voltage buses under EPU conditions. The proposed reduction of the voltage tolerance band of these relays in the Technical Specifications is more restrictive. The staff finds the proposed change conservative, and therefore, acceptable.

Emergency Diesel Generators

The design of the PTN Unit 3 and 4 EDGs is discussed in UFSAR Section 8.2.2.1.1.1. The EDGs have a base continuous rating of 2500 kilowatts (kW)and 2874 KW for Units 3 and 4, respectively. The licensee stated that EDG loading in the post-EPU state, even after taking into account EDG operation at extreme limits of revised frequency and voltage (discussed below), will remain within their ratings. The licensee has proposed changes to the EDG voltage and frequency operation, as follows; and proposed revision to the Technical Specifications, as necessary:

a. Revise the EDG frequency band from its current value of ±2% [percent] band to a new value of ±1% (59.4 Hz to 60.6 Hz).

b. Revise the EDG voltage band from its current value of ±10% to a new band of 3950 V to 4350 V (approximately ±5%).

In response to a staff RAI, the licensee provided the worst case loading analysis which showed EDG 3A having the least margin. The staff confirmed that the loading of the EDG 3A remains within the 2000-Hour rating under worst case conditions with Unit 3 in a loss of offsite power (LOOP) condition, Unit 4 in a SBO, and only EDG 3A available, with operation in the over-frequency range.

Since, the proposed TS changes are conservative, and the loadings remain within the EDG capacity and capability, the staff finds the proposed changes acceptable.

120V AC and 120V/208V Power Systems

The 120 V alternating current (ac) vital (safety-related) instrument power system and the 120 V ac nonvital (nonsafety-related) power systems are discussed in PTN UFSAR Sections 8.2.2.1.1. The licensee determined that even after considering the addition of new ac loads under EPU conditions, the loadings on these systems will remain within their capacity. In response to a staff RAI, the licensee in its letter dated March 31, 2011, identified some minor 120 V ac loads which will be added to vital and nonvital inverters. Since the loads are minor, the staff finds the licensee's assessment adequate and that these loads will have minimal impact on the 120 V ac vital and nonvital power systems.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ac onsite power system. The staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the ac onsite power system, and that the licensee will continue to meet the requirements of its current licensing basis with regard to PTN GDC 39 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the ac onsite power system.

2.3.4 DC onsite Power System

<u>Regulatory Evaluation</u>

The direct current (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 NRC staff's review covered the information, analyses, and referenced documents for the dc onsite power system. The NRC's acceptance criteria for the dc onsite power system is based on GDC-17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions. The applicable principal design criteria for PTN predate this criterion.

The PTN principal design criteria for electric systems is described in UFSAR Section 8.1.1. The emergency power for engineered safety features of PTN was designed prior to the

implementation of 10 CFR Part 50, Appendix A. The electrical power systems for PTN Units 3 and 4 were designed in accordance with the AEC's draft design criterion. PTN Units 3 and 4 GDC-39, "Emergency Power for Engineered Safety Features," is applicable for the design of the site electric power systems and mirrors the draft AEC design criterion for emergency power for engineered safety features. Subsequently, the AEC draft design criterion for emergency power for engineered safety features was implemented in 1971 as GDC-17, "Electric power systems," which established more specific requirements than previously identified. The licensee performed an evaluation of the site electrical system design in 1982 and concluded that PTN complies with the requirements of GDC-17.

PTN GDC-39 requires that alternate power systems shall be provided and designed with adequate independency, redundancy, capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite power system and the offsite power system shall each, independently, provide this capacity assuming a failure of a single active component in each system.

Specific review criteria are contained in SRP Sections 8.1 and 8.3.2

NRC Technical Evaluation

The dc power system is discussed in PTN Units 3 and 4 UFSAR Section 8.2.2.3. The NRC staff reviewed the licensee's submittal to determine whether the dc system and its components would remain capable of performing their intended design functions at EPU conditions. The evaluation is based on the system's required design functions and upon a comparison between existing equipment ratings and the anticipated operating requirements at EPU conditions.

By letter dated March 31, 2011, the licensee stated that nine modifications will be implemented for EPU that will result in minor load changes to the safety-related and nonsafety-related batteries as follows:

1. Replacement of the feedwater isolation valves will add dc solenoids to the safety-related portion of the dc system.
2. Electro-hydraulic controls (EHC) upgrade will add dc solenoids, which will add very low power requirements to the nonsafety-related dc power system.
3. Leading edge flow meter (LEFM) feedwater flow metering will add ac loads to the nonsafety-related inverters.
4. Turbine digital controls upgrade will add ac loads to the nonsafety-related inverters.
5. Feedwater heater drains digital controls upgrade will add ac loads to the nonsafety-related inverters.
6. Repowering of the alternate spent fuel pool pump will add control circuit load to the safety-related batteries.
7. Replacement of the power system stabilizer (PSS) will add load to the nonsafety-related batteries.

8. Replacement of the motor operated damper for the normal containment coolers will add a momentary load to the vital inverters.
9. The pressurizer setpoint and control modification will replace 3 existing indicators on each unit, adding load to the vital inverters.

The above modifications have minor load impact on the dc power system. In response to a staff RAI, the licensee in its letter dated March 31, 2011, provided margins available for the safety-related and nonsafety-related batteries under EPU conditions. The staff verified that the unused system capacity associated with the batteries and chargers continue to provide adequate margin even after considering the impact of above modifications.

The licensee also stated that Appendix R program evaluations did not result in any 125 V dc load changes. The SBO mitigation strategy at PTN does not require dc battery system coping analysis, since PTN is based on providing the plant's blacked-out unit with Alternate ac (Aac) source within 10 minutes. Therefore, the staff finds that there is no impact on PTN's capability to mitigate consequences of an SBO or Appendix R event under EPU conditions.

Conclusion

The NRC staff has 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 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 PTN GDC 39 following implementation of the proposed EPU. The system has the capacity and capability to supply power to all safety loads and other required equipment. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the dc onsite power system.

2.3.5 Station Blackout

Regulatory Evaluation

A station blackout (SBO) refers to a complete loss of ac electric power to the essential and nonessential switchgear buses in a nuclear power plant. An SBO involves the LOOP concurrent with a turbine trip and failure of the onsite emergency ac power system. An SBO does not include the loss of available ac power to buses fed by station batteries through inverters or the loss of power from Aac sources.

The PTN design relative to its conformance to 10 CFR 50.63, "Loss of All Alternating Current Power" (SBO Rule), is based on evaluations using the guidance from NUMARC 87-00, "Guidelines and Technical Basis for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," dated November 20, 1987, and Regulatory Guide 1.155, "Station Blackout," dated August 1988.

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 an SBO are based on 10 CFR 50.63. 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.

NRC Technical Evaluation

The licensee reevaluated the following SBO issues using the guidelines of NUMARC 87-00, and Regulatory Guide 1.155, corresponding to operation of PTN at EPU conditions:

- SBO Duration: EPU operation does not impact the factors, which determined current SBO duration of 8 hours. Therefore, current SBO duration remains the same.

- Aac Source: Each EDG has the capacity to maintain both units in Hot Standby for the postulated eight-hour coping period. All of the auto-connect loads and required manual loads associated with an EDG and its respective unit for a loss of offsite power condition plus the additional loads required by the opposite unit, can be supplied by any one EDG. EDG loading will increase at EPU due to an increase in assumed salinity of the intake cooling water; however, SBO loading remains bounded by the 2000-hour ratings of the EDGs.

- Condensate Inventory for Decay Heat Removal: At EPU conditions, the minimum condensate storage tank (CST) volume of 210,000 gallons per unit will support a hot standby duration of 18 hours, which bounds the SBO requirement of 8 hours of hot standby. Therefore the CSTs will continue to satisfy the SBO Rule.

- Class 1E Battery Capacity: According to Section 1.2 of NUMARC 87-00, the battery capacity coping assessment is not required if the Aac is available within 10 minutes of onset of SBO to power the shutdown buses. Since, PTN SBO analysis is based on availability of Aac within 10 minutes to power the shutdown buses, Class 1E battery capacity is not required to be evaluated corresponding to SBO EPU conditions.

- Compressed Air: There will be no change to the diesel driven instrument air system corresponding to EPU conditions.

- Effects of Loss of Ventilation: The EPU will not affect the ability to restore the Aac source within 10 minutes of confirmation of an SBO event, and power the necessary ventilation equipment. As EPU will not affect the 10-minute AAC strategy, based on NUMARC 87-00, Section 7.2.4, a coping assessment for plant heating, ventilation and air conditioning during an SBO event is not required. Further, according to Section 7.2.4, only dominant area of concern for a pressurized water reactor is the turbine driven auxiliary feedwater (AFW) pump room. At PTN, AFW pumps are located outdoors; therefore, AFW pump room ventilation is not a concern.

- Containment Isolation: The SBO containment isolation assessment is not affected by EPU and will therefore remain in compliance with the SBO Rule.

- Reactor Coolant Inventory: The EPU will result in no modifications to the reactor coolant system or chemical and volume control system (CVCS) that will alter system leakage or

charging ability during an SBO event. Therefore, EPU conditions will have no impact on previous SBO evaluation.

- Auxiliary Feedwater Flow (AFW): The turbine-driven AFW pump is used to maintain the units in a safe hot standby condition during an SBO event. The AFW system requirements at LOOP and SBO bound the EPU conditions.

The licensee also determined that the EPU will not impact other SBO issues such as procedures and training, plant modifications, quality assurance and technical specifications, and EDG reliability program.

On April 1, 2011, the NRC staff requested additional information regarding the statement in subsection 2.3.5.2.3 of the LR, which concludes that the EPU will not affect the ability to fulfill the requirements of PTN's heating, ventilation, and air conditioning system during an SBO event. It is stated in this section that heat loads in the buildings have either not increased or when increased, the increase is minor and well within the capacity of the area ventilation. The staff asked the licensee to provide the details of the evaluations performed, and compare the results with the pre-EPU conditions.

By letter dated April 28, 2011, the licensee stated that a qualitative evaluation of the effect of the EPU on the SBO ventilation had been performed. The licensee identified the following areas as requiring ventilation during an SBO and addressed the heat loads and the adequacy of the ventilation and cooling systems in those areas.

- Emergency Diesel Generator (EDG) Buildings
- Control Room
- Electrical Equipment Rooms (EERs)
- Load Center and Switchgear Rooms
- Battery Room
- Containment
- Computer/Cable Spreading Room
- Auxiliary Building

The EDG building heat loads will increase slightly due to increased EDG loads at EPU. At Unit 3, the criteria for air temperature is that it must stay below 115 °F to preclude derating of the engine, while at the same time support the temperature for electrical equipment located in the room. The location of the air intake is such that combustion air temperature remains close to outside ambient. Since the EPU does not affect the configuration of the intakes, increases in EDG loading will have little effect on the engine performance or on the electrical equipment operation at Unit 3. The Unit 4 EDG buildings are divided into four rooms each, consisting of the engine room, diesel oil transfer pump room, 4160 bus room, and the diesel control panel room. No ventilation is provided to the diesel oil transfer pump room during an SBO, as the day tank provides sufficient capacity for the duration of the SBO. The ventilation systems in the 4160 bus rooms and the control panel rooms are considered adequate as the heat loads in these rooms during an SBO are not impacted. The three engine radiator fans in the engine room serve as exhaust fans. The licensee stated that two out of three radiator fans will provide

an adequate ventilation system for the room and also support continuous EDG operation at basic overload rating.

The licensee stated that other than modifications to a small number of control room indicators, there are no changes to heat loads in the control room. The NRC staff agrees with the licensee's assessment that these changes will have a negligible impact on the overall heat load in the control room.

The licensee stated that changes in EPU heat loads from power cables are insignificant in the auxiliary building EER, and therefore, the ventilation provided to the EER during SBO conditions will be adequate.

The licensee stated that there would be a drastic reduction in heat loads in the load center and the switchgear rooms and the rooms will be provided with normal ventilation and air conditioning during an SBO as during normal operation, thus ensuring sufficient cooling to these rooms. Likewise, the computer/cable spreading rooms will also have reduced heat loads during an SBO, but the rooms will be provided with full complement of cooling during an SBO as during normal operation.

The size and the number of batteries in the battery rooms will not change as a result of the EPU. The licensee stated that minimal increases in the safety-related dc loading as a result of the EPU will have an insignificant impact on heat loading in the battery rooms. In addition, the ventilation system will be operational during an SBO.

The licensee stated that the SBO heat loads in the auxiliary building are significantly less than normal operation. By letter dated April 28, 2011, the licensee clarified that a single auxiliary building exhaust fan will be utilized during an SBO, as opposed to the statement in the LR that both supply and exhaust fans will be used. The licensee stated that in this alignment flow rate is decreased by only 3 percent from normal operation and that combined with the significant reduction in the heat loads, the SBO ventilation configuration will be adequate during an SBO conditions.

With respect to containment, the licensee stated NUMARC 87-00, Revision 0 assumes that temperatures in containment resulting from loss of ventilation are enveloped by LOCA and HELB temperature profiles. The licensee stated that safe shutdown equipment is qualified for accident environments under the plant's electrical equipment EQ program, thus providing assurance of operability of SBO equipment inside containment.

The resolution of the SBO issue for PTN is based on using plants EDGs to provide alternate safety-related, AC power source within 10 minutes following confirmation of a SBO event. The ventilation systems will be re-started on/or about that time. Based on only minor changes in heat loads and the availability of cooling systems during the SBO, the NRC staff concludes that the licensee evaluations on the adequacy of cooling during the SBO is acceptable.

The staff reviewed the licensee's SBO assessment and finds that the PTN will continue to have the necessary capability to mitigate the consequences of an SBO event under EPU conditions.

Conclusion

The NRC staff reviewed the licensee's assessment of the effects of the proposed EPU on the plant's ability to cope with and recover from a SBO event for the period of time 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 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 systems are provided to (1) control plant processes having a significant impact on plant safety, (2) initiate the reactivity control system (including control rods), (3) initiate the engineered safety features (ESF) systems and essential auxiliary supporting systems, and (4) achieve and maintain a safe shutdown condition of the plant. The Nuclear Regulatory Commission (NRC) staff conducted a review of the reactor trip system (RTS), engineered safety feature actuation system (ESFAS), safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed extended power uprate (EPU) technical specifications (TS) changes to ensure that these systems and any changes necessary are adequately designed such that the systems continue to meet their safety functions. The NRC staff's review was also conducted to ensure that failures of the systems do not affect safety functions. The NRC's acceptance criteria related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and General Design Criteria (GDC) described in Turkey Point Nuclear Plant (PTN) updated final safety analysis report (UFSAR). The staff notes that the PTN general design criterias (GDCs) were developed based on the 1967 Atomic Energy Commission Proposed General Design Criteria which predated those provided today in 10 CFR 50, Appendix A, "General Design Criteria for Nuclear Power Plants." The PTN GDCs applicable to the instrumentation and controls associated with reactor protection system, ESFAS, and plant control systems are as follows:

PTN GDC-1, Quality Standards
PTN GDC-11, Control Room
PTN GDC-12, Instrumentation and Control Systems
PTN GDC-14, Core Protection System
PTN GDC-19, Protection System Reliability
PTN GDC-20, Protection System Redundancy and Independence
PTN GDC-23, Protection Against Multiple Disability for Protection Systems
PTN GDC-26, Protection Systems Fail-Safe Design

The NRC staff reviewed the proposed TS changes in the application against the regulatory requirements and regulatory guidance listed below to verify the instrumentation can perform their safety functions.

The NRC staff considered the following regulatory requirements:

- In 10 CFR 50.36, "Technical Specifications," the Commission established its regulatory requirements related to the contents of the TS. Specifically, 10 CFR 50.36 states that "each applicant for a license authorizing operation of a production or utilization facility shall include in its application proposed technical specifications in accordance with the requirements of this section."

- In addition, 10 CFR 50.36(c)(3) states, "Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met."

The NRC staff reviewed the proposed TS changes against the following regulatory guidance:

- RS-001, Revision 0, "Review Standard for Extended Power Uprates," U.S. Nuclear Regulatory Commission, December 2003.[29]

- RIS 2006-17, "NRC Staff Position on the Requirements of 10 CFR 50.36, 'Technical Specifications,' Regarding Limiting Safety System Settings during Periodic Testing and Calibration of Instrument Channels," U.S. Nuclear Regulatory Commission, August 24, 2006.[30]

- Technical Specifications Task Force (TSTF) Traveler, TSTF-493, "Clarify Application of Setpoint Methodology for LSSS Functions," Revision 4, dated January 5, 2010, and an errata sheet, "Transmittal of TSTF-493, Revision 4, Errata," dated April 23, 2010,[31] clarify the application of setpoint methodology.

- Federal Register Notice, "Notice of Availability of the Models for Plant-Specific Adoption of Technical Specifications Task Force Traveler TSTF–493, Revision 4, 'Clarify Application of Setpoint Methodology for LSSS Functions'," May 11, 2010 (75 FR 26294).

- Regulatory Guide (RG) 1.105, "Setpoints for Safety-Related Instrumentation," Revision 3, issued December 1999,[32] describes a method that the NRC staff considers acceptable for complying with the agency's regulations for ensuring that setpoints for safety-related instrumentation are initially within and remain within the TS limits.

The NRC staff specifically verified that the proposed footnotes and applicable functions are identified in Appendix A to TSTF-493, Revision 4, and evaluated the setpoint calculations for all the revised limiting safety system setting (LSSS) setpoints. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

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[29] ML100060064
[30] ML051810077
[31] ML101160026
[32] ML993560062

NRC Technical Evaluation

Suitability of Existing Instruments

For the proposed power uprate, the licensee evaluated each existing instrument of the affected nuclear steam supply systems and balance-of-plant systems to determine its suitability for the revised operating range of the affected process parameters. Where operation at the power uprate condition impacted safety analysis limits, the licensee verified that the acceptable safety margin continued to exist under all conditions of the power uprate. Where necessary, the licensee revised the setpoint and uncertainty calculations for the affected or new instruments. Apart from a few devices that needed change, the licensee's evaluations found most of the existing instrumentation acceptable for the proposed power uprate operation. The licensee also evaluated the changes to instrument ranges and setpoints to ensure those changes will not adversely affect the functions performed by the instruments.

Instrument Setpoint Methodology

The set of instrument channel allowable values (AVs) applicable to TSTF-493 are those safety-related functions delineated within Attachment 2 of the TSTF-493, Revision 4, model application, which is included in the NRC's *Federal Register* notice of availability entitled, "Clarify Application of Setpoint Methodology for LSSS Functions."

The staff noted that the licensee proposed to revise several LSSS setpoint values of the RTS and ESFAS systems in accordance with TSTF-493. Therefore, the requirements of TSTF-493, Option A, apply to those proposed setpoint changes. When adopting Option A, the licensee must do the following:

- Provide a plant-specific evaluation that includes the calculation basis for the limiting trip setpoint (LTSP), nominal trip setpoint (NTSP)(referred to as the NTS by the licensee), AV, as-found tolerance band (AFT), and as-left tolerance band (ALT) for the list of instrument function setpoints proposed to be changed.

- Provide a description of the program methods for ensuring that the set of appropriate safety-related instrument channels will function as required by verifying that the limits of the AFTs and ALTs are consistent with the established setpoint methodology. The description must show how the proposed plant licensing basis meets the guidance provided in Regulatory Information Summary RIS 2006-17, "NRC Staff Position on the Requirements of 10 CFR 50.36, 'Technical Specifications,' regarding Limiting Safety System Settings during Periodic Testing and Calibration of Instrument Channels" and Regulatory Guide (RG) 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation."

- Provide a description of the program to identify the measures to be taken to ensure that the associated instrument channel is capable of performing its safety functions in accordance with applicable design requirements and associated analyses, including information regarding the controls employed to ensure that the as-left trip setting after completion of the required periodic surveillance is consistent with the setpoints

determined using the proposed setpoint methodology, and the plant corrective action process for restoring channels to operable status.

- Provide documentation, including summary calculations, of the methodology used for establishing the LTSP, NTSP, AV, AFT, and ALT indicating the related analytical limits (ALs).

The licensee submitted the document, WCAP-17070-P, Revision 0, “Westinghouse Setpoint Methodology for Protection Systems Turkey Point Units 3 and 4,” issued April 2010[33] (WCAP-17070-NP, Revision 0[34]), and identified that the proposed instrument setpoint changes in the TS are established using the performance-based setpoint methodology. The staff reviewed this methodology for the proposed RTS and ESFAS setpoint changes and noted that the document does the following:

- Defines each individual uncertainty term

- Identifies the general algorithm used to determine the total loop uncertainty (TLU) for a trip function

- Lists the applicable uncertainty terms for each RTS/ESFAS trip function proposed to be revised

- Describes the basic uncertainty algorithm

- Provides sample channel statistical allowance (CSA) calculation

- Provides a table with AL, AV, NTSP, total allowance (TA), CSA, and margin values

By letter dated January 28, 2011,[35] in response to the staff’s request for additional information, the licensee then supplemented the AFT and ALT values for all revised setpoints listed in Table 3-11 of WCAP-17070-P and described how it used two sample calculations to determine these values. In addition, the licensee provided the criterion used to establish the AFT and ALT. The licensee also provided the missing technical evaluation and summary setpoint calculations for Trip Function 15.a, “Turbine Trip-Emergency Trip Header Pressure,” listed in TS Table 2.2-1, “Reactor Trip System Instrumentation.”

The staff notes that the licensee clearly defined the applicable uncertainty terms and uses the square-root-sum-of-squares (SRSS) method for the basic CSA calculations, which is consistent with American National Standards Institute/Instrumentation, Systems, and Automation Society (ANSI/ISA)-67.04.01-2006, “Setpoints for Nuclear Safety-Related Instrumentation.” The licensee has included the appropriate and applicable uncertainties for each RTS/ESFAS trip function in the WCAP-17070-P report. The licensee has evaluated and has confirmed that the RTS/ESFAS trip function uncertainty calculations are consistent with the guidance of RG 1.105, Revision 3, including using 95/95 tolerance limit acceptance criteria.

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[33] ML103560169
[34] ML103560188
[35] ML110330190

The NRC staff also notes that, within the individual licensee instrument channel setpoint calculation used in WCAP-17070-P, the licensee uses the term "channel statistical allowance," which can be equated to the term "total loop uncertainty" used by NRC and the nuclear industry. The staff notes that, within the Westinghouse Electric Company technical reports of the late 1970s and early 1980s, the term "channel statistical allowance" is used to estimate the likely maximum uncertainty for anticipated channel performance deviation, which is then to be compared with the allowance between the previously established NTSP and its associated AL (identified as the "total allowance") to ensure that the estimate of such deviation will not exceed these margins. In establishing a high confidence margin between the new NTSPs and their associated ALs, the NRC staff notes that the CSA term is equivalent to the TLU term because it is applied to the required margin between the LTSP and the AL. This TLU (or CSA) consists of an appropriate algebraic and statistical combination of all of the identified error terms for the channel.

In response to the staff's request for additional information, the licensee provided the necessary definitions and the summary calculations (including NTSP, AV, AFT, and ALT) for the revised setpoints as follows:

> Safety Analysis Limit (SAL or AL)—The parameter value in the updated final safety analysis report (UFSAR) safety analysis or other plant operating limit at which a reactor trip or actuation function is assumed to be initiated.
>
> Channel Statistical Allowance (CSA)—The combination of the various uncertainties via SRSS and algebraic techniques.
>
> Nominal Trip Setpoint (NTS or NTSP)—A bistable trip setpoint in plant procedures. This value is the nominal values to which the bistable is set, as accurately as reasonably achievable.
>
> Rack Calibration Accuracy (RCA)—Rack calibration accuracy is defined as the two-sided calibration tolerance about the NTS of the process racks.

For the LSSS setpoints that were identified as primary RTS or ESFAS system settings having an AL (referred to as SAL by the licensee and evaluated in the plant safety analysis), the licensee used the following steps to calculate NTSP (or NTS, as referred by the licensee) and AV:

(1) $TA = CSA + M$

(2) $NTS = SAL \pm TA$

(3) $AV = NTS \pm RCA$

Where,

TA = total allowance
M = safety margin based on engineering judgment or a historical value that has been demonstrated over time to result in adequate operational margin
± = + or – the value depend on the direction of conservatism

The staff notes that this method of AV calculation uses the same concept as "Method 3" in Instrumentation, Systems, and Automation Society (ISA) RP67.04 Part II, "Methodology for the Determination of Setpoints for Nuclear Safety-Related Instrumentation," issued in 1994. The NRC staff had raised concerns in the 2003–2006 timeframe regarding this instrument setpoint methodology and concluded that the use of Method 3 resulted in the potential for instrument channels to operate beyond their analytical limits.

The staff further reviewed the setpoint calculation for each proposed LSSS setpoint listed in Table 3-11 of WCAP-17070-P and found that the licensee calculated the safety margin by the following equation:

(4) M = TA - CSA
= |SAL – NTS| - CSA

Where,

| | = absolute value

However this equation did not consider the worst-case limiting setting following the completion of surveillance when calculating the setpoint safety margin. In its initial evaluation, the staff concluded that the actual trip could result in the potential for the instrument channel to be operated beyond its analytical limit. The conservative safety margin calculation with the consideration of ALT setting should be:

(5) M = |SAL – NTS| - ALT - CSA

The staff raised this concern, especially for the safety margin of Function 2.a, "Power Range Neutron Flux-High," in TS Table 2.2-1, because the setting of this setpoint cannot maintain a positive safety margin by equation (5). After several RAI responses and teleconference discussions, the licensee revised the margin calculation of Function 2.a in TS Table 2.2-1 and revised WCAP-17070-P report to Revision 1[36] (WCAP-17070-NP, Revision 1[37]) to provide the sufficient safety margin for this setpoint. Function 2.a evaluation in Section 3.3.1 below provides more detail information for this margin calculation. The staff re-verified each proposed LSSS setpoint change to ensure that each proposed sepoint maintains a sufficient safety margin between the new NTSP and its associated AL.

The licensee used the following criterion to set AFT and ALT:

AFT = ALT = RCA

[36] ML11174A168
[37] ML11174A166

The staff notes that the AFTs are established for primary reactor trip and ESFAS initiation channels by first adding and subtracting the appropriate statistical combination of the channel operation test (COT) loop error components to the NTSP in order to establish the upper and lower limits of the AFT band and then ensuring that the worst-case limit of the AFT remains conservative with respect to the AV. The COT loop error components include the manufacturer's reference accuracy of the components in the loop, the calibration equipment accuracy, and rack drift, with no additional margin added. The licensee established AFT and ALT limits which are both equivalent to the RCA and are conservative. Therefore, the PTN setting criteria for the AFT and ALT are acceptable.

After the licensee updated WCAP-17070-P report to Revision 1 with revised setpoint calculation of Function 2.a in TS Table 2.2-1, the staff reviewed all of the proposed LSSS setpoint changes and found that the licensee has provided sufficient safety margins for all proposed LSSS setpoint changes which will be discussed in more detail below. Based on its review, the staff finds that the PTN setpoint methodology is acceptable for this license amendment because the setpoint calculation will provide adequate safety margins between the AV and AL, as well as adequate safety margin between the NTS and AL.

Technical Specifications Reactor Trip System Instrumentation

TS Table 2.2-1, "Reactor Trip System Instrumentation," Trip Setpoints

The licensee proposed to change the NTS and AV for RTS setpoints in TS Table 2.2-1. The NRC staff reviewed each revised setpoint calculation, including AV, NTS, TLU (which the licensee refers to as CSA), margin, AFT, and ALT, as discussed below, based on the revised analytical limits documented by the licensee in the submitted application.

Function 2.a Power Range Neutron Flux-High Setpoint

The licensee originally proposed to revise AL and TS setpoint values as follows:

AL: Revised from 118% [percent] RTP to 115% RTP
AV: Revised from ≤112% RTP to ≤109.6% RTP
NTS: 109% RTP
CSA: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

The EPU accident and transient analyses determined that, for some accidents, the analytical limit for the power range neutron flux-high reactor trip would need to be reduced from the current 118 percent to 115 percent rated thermal power (RTP). The licensee calculated the safety margin of this setpoint by equation (4) as follows:

M = |SAL – NTS| - CSA
= |115 – 109| - [[ ]]
= [[ ]] RTP

The NRC staff reviewed the calculation and found that a conservative safety margin calculation with the consideration of ALT setting by equation (5) would be:

M = |SAL – NTS| - ALT – CSA
= |115 – 109| - [[ ]]
= [[ ]] RTP

Therefore this LSSS setpoint does not maintain a sufficient safety margin and has the potential for the instrument channel to be operated beyond its analytical limit.

In response to the staff's concern, the licensee revised the NTS value from 109 percent RTP to 108 percent RTP for this setpoint and revised WCAP-17070-P report to Revision 1 to provide the sufficient safety margin. The staff reviewed the licensee's RAI response and found that the new setpoint values are as follows:

AL: 115% rated thermal power (RTP)
AV: less than or equal to 108.6% RTP
NTS: 108% RTP
CSA: [[ ]]
Margin: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

The NRC staff reviewed the calculations of each value of this LSSS setpoint and found that the licensee now maintains a margin of [[ ]] and operates with proper bounds of AFT and ALT. Thus, the licensee provides adequate assurance that the control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements. Therefore, the staff finds this setpoint change acceptable.

Function 5. Overtemperature ΔT—Notes 1 and 2

The licensee proposed to revise AL and TS setpoint values as follows:

AL: Revised from [[ ]] to [[ ]]

AV: Revised the statement in Note 2 from

"NOTE 2: The channels maximum trip setpoint shall not exceed its computed setpoint by more than 0.84% of instrument span."

to

"NOTE 2: The Overtemperature ΔT function Allowable Value shall not exceed the nominal trip setpoint by more than 0.5% ΔT span for the ΔT channel, 0.2% ΔT span for the Pressurizer Pressure channel, and 0.4% ΔT span for the f(ΔI) channel. No separate Allowable Value is provided for T_{avg} because this function is part of the ΔT value." Where f(ΔI) is a function of the indicated difference between top and bottom detectors of the power-range neutron ion chambers.

The accident and transient analyses have determined that the analytical limits utilized for the Overtemperature ΔT (OTΔT) reactor trip function will change for the EPU program. This function provides core protection to prevent departure from nucleate boiling (DNB) for all combinations of pressure, power, coolant temperature and axial power distribution for various transient analyses. The values for the OTΔT reactor trip setpoint constants are provided above for the EPU, and the OTΔT trip setpoint is recalibrated with OTΔT constants changed as above.

The staff reviewed the licensee's submittal and found the revised setpoint values to be as follows:

AL: [[ ]]
AV: as noted in Table 2.2-1, Notes 1 and 2, of the plant TS
NTS: 1.31 (131% RTP)
CSA: [[ ]]
Margin: [[ ]]
ΔT Channel AFT: [[ ]]
ΔT Channel ALT: [[ ]]
Pressurizer Pressure Channel AFT: [[ ]]
Pressurizer Pressure Channel ALT: [[ ]]
F(ΔI) Channel AFT: [[ ]]
F(ΔI) Channel ALT: [[ ]]
NIS Channel AFT: [[ ]]
NIS Channel ALT: [[ ]]

The NRC staff raised a concern regarding an observation that many of the individual uncertainty allowance terms within the revised setpoints have values of zero with little or no explanation as to why a value of zero is considered appropriate. The staff requested the licensee to explain its basis for the identification several of the "zero" uncertainty term values. In its responses the licensee provided justifications for the use of zero for several uncertainty values, stating that in many cases the use of the standard term was "not applicable" for the type of instrument channel being evaluated, and in other cases, the effect of the identified uncertainty was periodically [[ ]] through the conduct of periodic operating or instrument surveillances. The NRC staff requested further clarification regarding the use of "zero" in the uncertainties designed to account for the effects of [[ ]], which were identified within the T_{avg} -related and ΔT-related components for the setpoints for Overtemperature ΔT and Overpower ΔT. The licensee pointed out that [[ ]]. FPL conducts a quarterly surveillance procedure in which readings of the Eagle 21 system are obtained for T_{hot}, T_{cold}, ΔT, T_{avg}, T', and T" on all three channels and performs calculations to determine if ΔT_o, T' or T" need to be renormalized. If normalization of ΔT_o, T' or T" is required, FPL adjusts appropriate parameters within the Eagle 21 system. This process validates the justification provided by FPL concerning the representation of certain uncertainties, [[.]] FPL explained this normalization process for the

Overtemperature ΔT and Overpower ΔT in their RAI responses of January 19, 2012, January 31, 2012, and February 23, 2012.[38]

Finally, the NRC staff reviewed the calculations of each value of the LSSS setpoint and found that the licensee still maintains a margin of [[   ]] and operates with proper bounds of AFT and ALT. Thus, the licensee provides adequate assurance that the control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements. Based on the licensee providing an adequate safety margin with an allowance for maximum anticipated OTΔT, OPΔT, and RTD readings deviations during a refuel cycle, and the statements that a quarterly surveillance will be performed to monitor the approach to these allowances, the staff finds the licensee response acceptable.

Item for Follow-up Inspection

At the end of the first quarter (92 days) of power operations following implementation of the EPU, it is recommended that the NRC Region II Office perform a follow-up inspection to verify that this normalization procedure provided results that were consistent with or conservative with respect to the anticipated [[   ]] and deviations in ΔT_o, T' or T".

<u>Function 6.   Overpower ΔT—Notes 3 and 4</u>

The licensee proposed to revise AL and TS setpoint values as follows:

> AL: [[   ]]
>
> AV: Revised the statement in Note 4 from:
>
> "NOTE 4: The channel's maximum trip setpoint shall not exceed its computed trip setpoint by more than 0.96% of instrument span."
>
> to:
>
> "NOTE 4: The Overpower ΔT function Allowable Value shall not exceed the nominal trip setpoint by more than 0.5% ΔT span for the ΔT channel. No separate Allowable Value is provided for T_{avg} because this function is part of the ΔT value."
>
> The accident and transient analyses have determined that one of the constants utilized for the Overpower ΔT reactor trip function will change for the EPU program. This function prevents power density anywhere in the core from exceeding the design power density value. This provides assurance of fuel integrity under all possible overpower conditions.

The staff reviewed the licensee's submittal and found the revised setpoint values to be as follows:

---

[38] ML12023A032, ML120330397, and ML120580184

AL: [[ ]]
AV: as noted in Table 2.2-1, Notes 3 and 4, of the plant TS
NTS: 1.10 (110% RTP)
CSA: [[ ]]
Margin: [[ ]]
ΔT Channel AFT: [[ ]]
ΔT Channel ALT: [[ ]]

The NRC staff reviewed the calculations of each value of this LSSS setpoint and found that the licensee still maintains a margin of [[ ]] and operates with proper bounds of AFT and ALT. Thus, the licensee provides adequate assurance that the control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements. Therefore, the staff found this setpoint change acceptable.

Function 10. Reactor Coolant Flow-Low

The licensee proposed to revise AL and TS setpoint values as follows:

AL: Revised from 84.5% TDF(1) to 84.5% TDF(2)
AV: Revised from ≥88.8% of loop design flow(1) to ≥89.6% of loop design flow(2)
TRIP SETPOINT: 90% Loop Design Flow (unchanged, except removed ≥ sign)

(1) Current Loop Design Flow (TDF) = 85,000 gpm [gallons per minute]
(2) EPU Loop Design Flow (TDF) = 86,900 gpm

The EPU accident and transient analyses determined that the existing analytical limit (in% flow) for the Reactor Coolant Flow–Low reactor trip does not change from the current value. However, the value of Thermal Design Flow (TDF), i.e., loop design flow has changed for EPU. The current nominal trip setpoint of 90% of loop design flow will not change. However, the Allowable Value is changed to the value as described above.

The staff reviewed the licensee's submittal and found the revised setpoint values to be as follows:

AL: 84.5% TDF
AV: ≥89.6% TDF
NTS: 90% TDF
CSA: [[ ]]
Margin: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

The NRC staff reviewed the calculations of each value of this LSSS setpoint and found that the licensee still maintains a margin of [[ ]] and operates with proper bounds of AFT and ALT. Thus, the licensee provides adequate assurance that the control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements. Therefore, the staff found this setpoint change acceptable.

Function 11. Steam Generator Water Level-Low-Low

The licensee proposed to revise AL and TS setpoint values as follows:

AL: 4.0% Narrow Range Span (NRS) (unchanged)
AV: Revised from ≥8.15% NRS to ≥15.5% NRS
TRIP SETPOINT: Revise from ≥10% NRS to 16.0% NRS

The accident and transient analyses have determined that the analytical limit utilized in the Loss of Normal Feedwater/Loss of AC Power events will remain unchanged for the EPU. The steam generator water level low-low reactor trip (and ESFAS initiation) safety analysis limit for a Loss of Normal Feedwater/Loss of AC Power event is 4.0% Narrow Range Span (NRS). To account for instrument channel uncertainties for EPU conditions and to provide adequate margin for the Probability Risk Assessment analyses, the Technical Specification low-low setpoint will change from 10.0% NRS to 16.0% NRS and the Allowable Value will change from 8.15% to 15.5% to comply with the methodology as described in WCAP-17070-P.

The staff reviewed the licensee submittal and found the revised setpoint values to be as follows:

AL: 4.0% NRS
AV: ≥15.5% NRS
NTS: 16.0% NRS
CSA: [[ ]]
Margin: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

The NRC staff reviewed the calculations of each value of this LSSS setpoint and found that the licensee still maintains an NRS margin of [[ ]] and operates with proper bounds of AFT and ALT. Thus, the licensee provides adequate assurance that control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements. Therefore, the staff found this setpoint change acceptable.

Function 12. Steam/Feedwater Flow Mismatch Coincident with Steam Generator Water Level-Low

The licensee proposed to revise AL and TS setpoint values as follows:

Steam/Feedwater Flow Mismatch

AL: N/A
AV: Revised from "Feed Flow ≤23.9% below rated Steam Flow" to "Feed Flow ≤20.7% below rated Steam Flow."

Coincident with Steam Generator Water Level-Low

AV: Revised from ≥8.15% NRS to ≥15.5% NRS
TRIP SETPOINT: Revised from ≥10% NRS to 16.0% NRS

The current main steamline flow and main feedwater flow transmitters require changes to support EPU. The transmitters are currently calibrated for a range of 0 to 4.0×10^6 lbm/hr. The main steam and main feedwater flow transmitters will be recalibrated for a range of 0 to 5.0×10^6 lbm/hr (0% flow to 135.9% flow). The expanded range meets or exceeds the current range. The NTS does not require a change for EPU. However, as noted above, the Allowable Value changes from 23.9% to 20.7% below rated steam flow to comply with the methodology as described in WCAP-17070-P.

The steam generator water level low signal, coincident with steam flow/feedwater flow mismatch, provides a backup reactor trip that is not specifically credited in the safety analyses. Therefore, the trip function lacks an accident analysis limit upon which to base the NTS. However, the low level backup trip function is necessary in the event that a control/protection interaction failure scenario of the steam generator level low-low reactor trip function disables the reactor trip on low-low level.

The staff notes that the licensee set the trip setpoint and AV for the steam generator water level low based on performing the backup reactor trip at the same level as the steam generator low-low level trip which has been described in the previous section of Function 11 "Steam Generator Water Level-Low-Low."

The staff reviewed the licensee submittal and found that the revised setpoint values for Steam/Feedwater Flow Mismatch are as follows:

AL: N/A (not credited in the safety analyses)
AV: Revised from "Feed Flow ≤23.9% below rated Steam Flow" to
"Feed Flow ≤20.7% below rated Steam Flow"
NTS: "Feed Flow 20% below rated Steam Flow"
CSA: [[
]]
Margin: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

The NRC staff reviewed the calculations of each value of this LSSS setpoint and found that the licensee operates with proper bounds of AFT and ALT. Thus, the licensee provides adequate assurance that the control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements. Therefore, the staff found this setpoint change acceptable.

Function 15.a Turbine Trip-Emergency Trip Header Pressure

The licensee proposed to revise the following description form of the current TS:

15. Turbine Trip
    a. Autostop Oil pressure

to the proposed TS below:

15. Turbine Trip
    a. Emergency Trip Header Pressure

The licensee also proposed to revise the TS setpoint values as follows:

AV: Revised from ≥42 psig to ≥901 psig
TRIP SETPOINT: Revised from 45 psig to 1000 psig

The 300 psi mechanical hydraulic system which controls the turbine will be replaced with an 1800 psi electrical hydraulic control system as part of EPU. The change to the higher pressure Emergency Trip Header Pressure trip is reflective of the new higher pressure system. As per the current licensing basis, the Turbine Trip is not credited in the safety analyses.

The staff reviewed the licensee submittal and found the revised setpoint values to be as follows:

AL: N/A (not credited in the safety analyses)
AV: ≥901 pounds per square inch gauge (psig)
NTS: 1,000 psig
CSA: [[
]]
Margin: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

The NRC staff reviewed the calculations of each value of this LSSS setpoint and found that the licensee operates with proper bounds of AFT and ALT. Thus, the licensee provides adequate assurance that the control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements. Therefore, the staff found this setpoint change acceptable.

TS Table 3.3-1, "Reactor Trip System Instrumentation," Function 15.a Description

Under Function 15.a, "Turbine Trip (Above P-7)–Emergency Trip Header Pressure," the licensee proposed to revise the description form of the current TS from the following:

15. Turbine Trip (Above P-7)
    a. Autostop Oil pressure

to the proposed TS below:

15. Turbine Trip (Above P-7)
    a. Emergency Trip Header Pressure

This change is discussed above.

<u>TS Table 4.3-1, "Reactor Trip System Instrumentation Surveillance Requirements," Notes</u>

The licensee proposed to add Notes (a) and (b) in TS Table 4.3-1 to the applicable channel calibration and analog channel operational test surveillance requirements of the RTS functions with as-found and as-left criteria, in accordance with TSTF-493, Revision 4. The licensee proposed to add Notes (a) and (b) for the following functions in TS Table 4.3-1:

2.a Power Range, Neutron Flux–High Setpoint

5. Overtemperature ΔT Note 1 (K1)

6. Overpower ΔT Note 3 (K4)

10. Reactor Coolant Flow-Low

11. Steam Generator Water Level-Low-Low

12. Steam Generator Water Level-Low Coincident with Steam/Feedwater Flow Mismatch

15.a Turbine Trip-Emergency Trip Header Pressure

The NRC staff reviewed Notes (a) and (b) and found that they are consistent with the wording of the two notes in TSTF-493, Revision 4. Therefore, the staff finds the addition of Notes (a) and (b) acceptable.

<u>Technical Specifications Engineered Safety Feature Actuation System (ESFAS)</u>

The ESFAS instrumentation measures temperature, pressures, flows, and levels in the reactor coolant system, steam system, reactor containment, and auxiliary systems; actuates engineered safety features; and monitors their operation. The quantity and types of process instrumentation provided ensures safe and orderly operation of all systems and processes over the full operating range of the unit.

As mentioned in the previous section, the current main steamline flow and main feedwater flow transmitters require changes to support the EPU. The main steam and main feedwater flow transmitters will be recalibrated for a range of 0 to 5.0×10^6 pound mass per hour (lbm/h) (0 percent flow to 129 percent flow). The expanded range meets or exceeds the current range.

TS Table 3.3-3, "Engineered Safety Feature Actuation System Instrumentation," Trip Setpoints

The licensee proposed to change the NTS and AVs for the ESFAS setpoints in TS Table 3.3-3 as shown below. The NTS values are the LSSS values that are derived from the analytical values and adjusted to account for the specific instrument uncertainties.

Function 1.f "Safety Injection (SI)-Steamline Flow-High Coincident with Steam Generator Pressure-Low,"

The licensee proposed to revise AL and TS setpoint values as follows:

Steamline Flow-High

AL: Revised from the following current wording:

"60% full steam flow at 0% load increasing linearly from 20% load to a value of 120% steam flow at full load"

to the proposed wording below:

"60% full steam flow at 0% load increasing linearly from 20% load to a value of 129% steam flow at full load"

AV: Revised from the following current wording:

"≤ A function defined as follows: A Δp corresponding to 44% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 116.5% steam flow at full load"

to the proposed wording below:

"≤ A function defined as follows: A Δp corresponding to 41.2% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 114.4% steam flow at full load"

TRIP SETPOINT:

"≤ A function defined as follows: A Δp corresponding to 40% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 114% steam flow at full load" (unchanged, except removed ≤ sign and added Notes (a) and (b))"

The accident analyses for the EPU determined that the analytical limit for the high steam flow function is 60% steam flow at 0% load increasing linearly from 20% load to a value of 129% of new total steam flow at full load. The full load value is an increase from the existing value of 120% current steam flow. The existing nominal trip setpoint of less than or equal to a Δp corresponding to 40% steam flow at 0% load increasing linearly from 20% load to a value

corresponding to 114% steam flow at full load is acceptable for the EPU and is not changing. However, the Allowable value is changed to the values described above.

The licensee proposed to revise TS setpoint values as follows:

Steam Generator Pressure-Low[(4)]

Steamline pressure low—outside containment steamline break
AL: 432.3 psig (unchanged)

Steamline pressure low—inside containment steamline break

AL: Revised from 432.3 psig to 566.3 psig

Steamline pressure low (for both outside and inside containment steamline break)

AV: Revised from ≥588 psig to ≥607 psig
TRIP SETPOINT: 614 psig (unchanged, except removed ≥ sign and added Note(a) and (b))

The licensee also proposed to add the following new Note (4):

(4) Time constants utilized in the lead-lag controller for Steam Generator Pressure-Low Steamline Pressure-Low are $t_1 \geq 50$ seconds and $t_2 \leq 5$ seconds. CHANNEL CALIBRATION shall ensure that these time constants are adjusted to these values.

The accident analyses determined that the analytical limit for the steamline pressure low SI inside containment steam break will need to be revised to 566.3 psig for the EPU. This is an increase from the existing value of 432.3 psig. The current SAL of 432.3 psig remains applicable for the outside containment steam break analysis. Although the Safety Analysis Limit is increasing to 566.3 psig, the current nominal trip setpoint of 614 psig has adequate margin to accommodate the new SAL and will not change. There is however, a change required to the Allowable Value as shown below.

The staff reviewed the licensee submittal and found the revised setpoint values to be as follows:

Steamline pressure low—outside containment steamline break

AL: 432.3 psig
AV: ≥607 psig
NTS: 614 psig
CSA: [[ ]]
Margin: [[ ]]

AFT: [[ ]]
ALT: [[ ]]

Steamline pressure low—inside containment steamline break

AL: 566.3 psig
AV: ≥607 psig
NTS: 614 psig
CSA: [[ ]]
Margin: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

The NRC staff reviewed the calculations of each value of this LSSS setpoint and found that the licensee still maintains a margin of [[ ]] (outside containment steamline break setpoint) and a margin of [[ ]] (inside containment steamline break setpoint) and operates with proper bounds of AFTs and ALTs. Thus, the licensee provides adequate assurance that the control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements.

The addition of the lead/lag addressed in the new Note (4) on the steamline pressure input causes the safety injection signal to occur significantly faster and reduces the total mass that enters containment. The NRC staff evaluated the response time of this lead/lag; however, the effects of these time constant values are analyzed in Section 2.8 of this safety evaluation.

The staff requested a RAI concerned with the surveillance requirements needed to assure that the installed circuitry will meet the required response time to achieve a safety injection initiation signal for this coincident steamline low pressure and steamline high flow signals. By letter dated August 16, 2011,[39] the licensee confirmed that in addition to adding a note within TS Table 3.3-3 concerning the magnitude of the lead/lag time constants to be maintained, FPL will revise the existing loop calibration and periodic surveillance procedures for steam break protection instrumentation to include verification of this lead/lag module time settings to ensure that the steam generator pressure instrument loops will meet the time response determined by the analysis. This will assure that the installed circuitry will meet the required time response necessary to achieve safety injection initiation and main steamline isolation. Surveillance periodicity will be consistent with current TS 4.3.2.1, Table 4.3-2, Functional Unit 4.d for steamline flow–high, coincident with steam generator pressure–low, which is calibrated once per refueling outage (18 months). Based on this evaluation, the staff found that this setpoint change and the addition of Note (4) acceptable.

[39] ML11231A248

Function 4.d Steamline Isolation-Steamline Flow-High Coincident with Steamline Pressure-Low or T_{avg}-Low

The licensee proposed to revise AL and TS setpoint values as follows:

Steam Flow-High

AL: Revised from the following current wording:

"60% full steam flow at 0% load increasing linearly from 20% load to a value of 120% steam flow at full load"

to the proposed wording below:

"60% full steam flow at 0% load increasing linearly from 20% load to a value of 129% steam flow at full load"

AV: Revised from the following current wording:

"≤ A function defined as follows: A Δp corresponding to 44% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 116.5% steam flow at full load"

to the proposed wording below:

"≤ A function defined as follows: A Δp corresponding to 41.2% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 114.4% steam flow at full load"

TRIP SETPOINT:

"A function defined as follows: A Δp corresponding to 40% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 114% steam flow at full load" (unchanged, except removed ≤ sign and added Notes (a) and (b))

The accident analyses for the EPU determined that the analytical limit for the high steam flow function is 60% steam flow at 0% load increasing linearly from 20% load to a value of 129% steam flow at full load. The full load value is an increase from the existing value of 120% steam flow.

The existing nominal trip setpoint of less than or equal to a Δp corresponding to 40% steam flow at 0% load increasing linearly from 20% load to a value corresponding to 114% steam flow at full load is acceptable for the EPU and is not changing. However, the Allowable value is changed to the values described above.

The licensee proposed to revise AL and TS setpoint values as follows:

Steam Generator Pressure-Low[4] (for both outside and inside containment steamline break)

AV: Revised from ≥588 psig to ≥607 psig
TRIP SETPOINT: 614 psig (unchanged, except removed ≥ sign)

The licensee also proposed to add the following new Note (4):

(4) Time constants utilized in the lead-lag controller for Steam Generator Pressure-Low Steamline Pressure-Low are t1 ≥ 50 seconds and t2 ≤ 5 seconds. CHANNEL CALIBRATION shall ensure that these time constants are adjusted to these values.

The staff reviewed the licensee submittal and found the revised setpoint values to be as follows:

Steamline pressure low—outside containment steamline break

AL: 432.3 psig
AV: ≥607 psig
NTS: 614 psig
CSA: [[ ]]
Margin: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

Steamline pressure low—inside containment steamline break

AL: 566.3 psig
AV: ≥607 psig
NTS: 614 psig
CSA: [[ ]]
Margin: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

The NRC staff reviewed the calculations of each value of this LSSS setpoint and found that the licensee still maintains a margin of [[ ]] (for inside containment steamline break setpoint) and a margin of [[ ]] (for outside containment steamline break setpoint) and operates with proper bounds of AFTs and ALTs. Thus, the licensee provides adequate assurance that the control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements.

The addition of the lead/lag addressed in the new Note (4) on the steamline pressure input is exactly the same as that in Function 1.f, as stated above.

Function 5.c Feedwater Isolation-Steam Generator Water Level High-High

The licensee proposed to revise AL and TS setpoint values as follows:

AL: 96.8% NRS (not credited in the safety analyses)
AV: Revised from ≤81.9% NRS to ≤80.5% NRS
TRIP SETPOINT: 80% NRS (unchanged, except removed ≤ sign and added Notes (a) and (b))

Feedwater isolation on high steam generator level is not specifically credited in the safety analyses. However for operational considerations, the top of the instrument span is assumed with allowances for void fraction (maximum reliable indicated level (MRIL)). The uncertainty analysis is based on maintaining the operating limit below the maximum reliable indicated level of 96.8% narrow range span (NRS). The current trip setpoint of 80% NRS has adequate margin to accommodate the MRIL and will not change. There is however, a change required to the Allowable Value as shown above.

The staff reviewed the licensee submittal and found that the revised setpoint values are as follows:

AL: 96.8% NRS (not credited in the safety analyses)
AV: ≤80.5% NRS
NTS: 80% NRS
CSA: [[ ]]
Margin: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

The NRC staff reviewed the calculations of each value of this LSSS setpoint and found that the licensee still maintains an NRS margin of [[ ]] and operates with proper bounds of AFT and ALT. Thus, the licensee provides adequate assurance that the control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements. Therefore, the staff finds this setpoint change acceptable.

Function 6.b Auxiliary Feedwater-Steam Generator Water Level-Low-Low

The licensee proposed to revise AL and TS setpoint values as follows:

AL: 4.0% NRS (unchanged)
AV: Revised from ≥8.15% NRS to ≥15.5% NRS
TRIP SETPOINT: Revised from ≥10% NRS to 16.0% NRS

The accident and transient analyses have determined that the analytical limit utilized in the Loss of Normal Feedwater/Loss of AC Power events will not change for the EPU. The steam generator water level low-low reactor trip (and ESFAS initiation) safety analysis limit for a Loss of Normal Feedwater/Loss of AC Power event is 4.0% Narrow Range Span (NRS). To account for instrument

channel uncertainties for EPU conditions and to provide adequate margin for the Probability Risk Assessment analyses, the Technical Specification low-low setpoint will change from 10.0% NRS to 16.0% NRS and the Allowable Value will change from 8.15% to 15.5% as shown above.

The staff reviewed the licensee submittal and found the revised setpoint values to be as follows:

AL: 4.0% NRS
AV: ≥15.5% NRS
NTS: 16.0% NRS
CSA: [[ ]]
Margin: [[ ]]
AFT: [[ ]]
ALT: [[ ]]

The NRC staff reviewed the calculations of each value of this LSSS setpoint and found that the licensee still maintains an NRS margin of [[ ]] and operates with proper bounds of AFT and ALT. Thus, the licensee provides adequate assurance that the control and monitoring of this setpoint are established and maintained in a manner consistent with plant safety function requirements. Therefore, the staff finds this setpoint change acceptable.

<u>TS Table 4.3-2, "Engineered Safety Feature Actuation System Instrumentation Surveillance Requirements," Notes</u>

The licensee proposed to add Notes (a) and (b) in TS Table 4.3-2 to the applicable channel calibration and analog channel operational test surveillance requirements of the ESFAS functions with as-found and as-left criteria, in accordance with TSTF-493, Revision 4. The licensee proposed to add Notes (a) and (b) for the following functions in TS Table 4.3-2:

1.f Safety Injection (SI)-Steamline Flow-High Coincident with Steam Generator Pressure-Low

4.d Steamline Isolation-Steamline Flow-High Coincident with Steamline Pressure-Low or T_{avg}-Low

5.c Feedwater Isolation-Steam Generator Water Level High-High

6.b Auxiliary Feedwater-Steam Generator Water Level-Low-Low

The NRC staff reviewed these two notes and found that they are consistent with the wording of the two notes in TSTF-493, Revision 4. Therefore, the staff finds the addition of Notes (a) and (b) acceptable.

Additional Proposed Changes

The licensee proposed additional changes in its RAI response dated August 29, 2011,[40] as follows:

TS Table 2.2-1, "Reactor Trip System Instrumentation Trip Setpoints," Function 17.b

2) Turbine **First Stage** Pressure is revised to 2) Turbine **Inlet** Pressure.

TS Table 3.3-1, "Reactor Trip System Instrumentation," Function 17.b

Turbine **First Stage** Pressure is revised to Turbine **Inlet** Pressure.

TS Table 4.3-1, "Reactor Trip System Instrumentation Surveillance Requirements," Function 17.b

Turbine **First Stage** Pressure is revised to Turbine **Inlet** Pressure.

The staff notes that the change in the RTS interlock wording clarifies the turbine pressure measurement location based on installation of the new electro-hydraulic control (EHC) system; therefore, all the three proposed changes are acceptable.

The licensee also proposed to add Mode 3 in the "APPLICABLE MODES" column of TS Table 3.3-2, "Engineered Safety Feature Actuation System Instrumentation," Function 5, "Feedwater Isolation"

a. Automatic Actuation Logic and Actuation Relays
c. Steam Generator Water Level – High-High

The licensee proposed to add a new TS 3/4.7.1.7 with limiting condition for operation (LCO) requirements for the new feedwater isolation valves which is consistent with NUREG-1431, "Standard Technical Specifications Westinghouse Plants," Revision 3, June 2004 (STS) with applicability to Modes 1, 2 and 3. The staff notes that the current PTN LCO for the ESFAS feedwater isolation function applies to modes 1 and 2 only. The licensee's change to add Mode 3 in the TS Table 3.3-2, Function 5.a and Function 5.c is consistent with the STS, therefore, acceptable.

Control Systems

PTN designed reactor control systems to limit the plant transients for prescribed design load perturbations and within prescribed limits to preclude the possibility of a reactor trip in the course of these transients. During steady-state operation, the primary function of the reactor control is to maintain a programmed average reactor coolant temperature that rises in proportion to load. The control systems also limit nuclear plant system transients to prescribed limits about this programmed temperature for specified load perturbations. The licensee's evaluation of control systems resulted in the following changes at PTN:

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[40] ML11242A159

Turbine Inlet Pressure Instrumentation

PTN will install a new high pressure (HP) turbine rotor and replace the mechanical hydraulic turbine control system with an EHC system as part of the EPU. The new HP turbine is expected to generate a 0-100 percent power nominal inlet pressure of 0-671.4 psig. The licensee will recalibrate and scale the existing turbine first-stage pressure transmitters and associated indications to a range of 0-120 percent of expected EPU turbine inlet pressure of 100 percent. The full range of the transmitters is 0-1,000 psig. The inputs to each of the systems identified below will be recalibrated to respond at the appropriate value for the new power range of 0-120 percent.

- Anticipated transient without scram (ATWS) mitigation system actuation circuitry-arm/disarm circuit permissive P-20 at inlet pressure equivalent to 40 percent of turbine power
- P-5 permissive - steam dump to condenser permissive
- P-7 permissive - in conjunction with P-10 and low turbine power; blocks various reactor trips
- T_{ref} input to the reactor coolant T_{avg} control program and turbine bypass system
- EHC turbine control

Rod Control System Changes

The licensee will change the EPU 0-100 percent power T_{avg} temperature program (T_{ref}) from the current 547-577.2 degrees Fahrenheit (°F) to 547-583.0 °F based on a turbine inlet pressure of 0-671.4 psig. Once the T_{ref} program is calibrated with the turbine inlet pressure range and temperature control band, the rods are expected to respond as designed to average T_{avg} temperature deviations from T_{ref}.

The licensee will calibrate power mismatch circuits with the new turbine inlet pressure values of 0-100 percent, which will ensure that the power mismatch circuits will continue to provide the required anticipated rod speed with a deviation between nuclear power and turbine power.

Pressurizer Level Program and Pressurizer Pressure Control System

The licensee has proposed to revise the pressurizer level program for EPU to be 22.2 percent span at no-load conditions, increasing linearly to the full-load level (46.3 percent-60.0 percent), which varies based on T_{avg} of 570-583 °F. The pressurizer pressure control system features the actuation of the backup heaters and alarm on a high pressurizer level deviation of 5 percent. However, actuation of the backup heaters and alarm on a high pressurizer level deviation function is being removed for the EPU. This change will not impact the margin to a reactor trip for a 10 percent step load reduction transient.

Steam Dump Control and Turbine Bypass Systems

When the condenser is available, the condenser steam dumps are armed based on a rapid decrease in turbine first-stage pressure (equivalent to a load decrease of greater than 10 percent), and the dump valves either modulate open or are tripped open based on the magnitude of error (ΔT) between the measured T_{avg} and the reference temperature (T_{ref}) programmed of turbine first-stage pressure.

As described in Section 2.4.2, “Plant Operability (Margin to Trip),” of the licensing report, the licensee has verified that the current steam dump valve capacity at EPU conditions is sufficient to accommodate a rapid load decrease equivalent to 50 percent of RTP at a rate of 200 percent per minute. The licensee stated that the current T_{avg} load rejection and T_{avg} turbine trip steam dump setpoints are acceptable at EPU conditions for full power T_{avg} anywhere between 570 °F and 583 °F.

Anticipated Transient without Scram Mitigation System Actuation Circuitry

The changes to this circuitry are associated with the arming of permissive P-20, which arms/disarms the circuit at a turbine first-stage pressure equivalent to 40 percent of nuclear power and recalibrating the turbine inlet pressure, steamflow, and feedwater flow inputs for the EPU full-load values. The P-20 permissive will be recalibrated to arm/disarm at the appropriate turbine inlet pressure consistent with the new 0-100 percent power nominal turbine inlet pressure range of 0-671.4 psig.

P-5 Permissive Changes

The P-5 permissive is used to arm the steam dump to the condenser system for a fast load reduction (10 percent load). The permissive is based on the turbine first-stage pressure. The licensee will recalibrate this permissive from the turbine first-stage pressure input to arm the steam dumps at the value consistent with the new 0-100 percent power nominal turbine inlet pressure range of 0–671.4 psig.

P-7 Permissive Changes

The P-7 permissive is used to bypass the low pressurizer pressure reactor trips during low power or startup operation. It is also used to bypass reactor coolant low flow and reactor coolant pump breaker open in both loops. It is derived from a bistable circuit indicating a turbine load of less than 10 percent, as measured by both first-stage turbine pressure (two-out-of-two) and power range (three-out-of-four) less than approximately 10.0 percent. The power range input is supplied by the P-10 permissive. The licensee will recalibrate the input from the turbine first-stage pressure to actuate at the value consistent with the new 0–100 percent power nominal turbine inlet pressure range of 0–671.4 psig.

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. Within instrumentation and control review scope, the staff notes that none of

the above control system changes affect the licensee's compliance with the existing plant licensing basis; therefore, PTN continues to meet the current regulatory basis for the plant. In addition, the licensee will confirm the acceptability of these changes during power ascension testing.

The NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these systems and that the changes necessary to achieve the proposed EPU are consistent with the plant's design basis within instrumentation and control review scope. The NRC staff concludes that the instrumentation and controls system meets the requirements of 10 CFR 50.36, the guidance of RG1.105, Revision 3 and TSTF-493, Revision 4. The staff further concludes that the system will continue to meet the GDCs described in PTN UFSAR – PTN GDC 1, 11, 12, 14, 19, 20, 23, and 26. Therefore, the NRC staff finds the licensee's proposed EPU acceptable within instrumentation and control review scope.

2.4.2 Additional Review Areas

Measurement Uncertainty Recapture

Introduction

The licensee's EPU request includes a 1.7 percent measurement uncertainty recapture (MUR) power uprate by using the Cameron (formerly Caldon) Leading Edge Flow Meter (LEFM) CheckPlus^{TM} (√+) System feedwater flow meter. The LAR referenced Caldon Topical Report ER-80P, Revision 0, "Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the System," issued March 1997, and its supplement, Topical Report ER-157P, Revision 5, "Supplement to Topical Report ER-80P: Basis for a Power Uprate with the LEFM Check (√^{TM})or LEFM CheckPlus^{TM} (√+) System," issued October 2001. These topical reports, which are generically applicable to nuclear power plants, document the ability of the Caldon LEFM √^{TM} and √+ ^{TM} Systems to increase the accuracy of flow measurement. The NRC-approved Topical Report ER-80P and its supplement, Topical Report ER-157P, in safety evaluations (SEs) dated March 8, 1999, and December 20, 2001, respectively. Together, these two reports and their respective safety evaluations provide a generic basis for an MUR power uprate.

The licensee's submittal also provides several attachments (proprietary) that describe the plant-specific bases for the proposed MUR uprate at PTN:

- Cameron Engineering Report ER-748, Revision 1, "Meter Factor Calculation and Accuracy Assessment for Turkey Point Nuclear Power Plant Unit 3," issued June 2010.

- Cameron Engineering Report ER-752, Revision 1, "Meter Factor Calculation and Accuracy Assessment for Turkey Point Nuclear Power Plant Unit 4," issued June 2010.

- Cameron Engineering Report ER-783, Revision 2, "Bounding Uncertainty Analysis for Thermal Power Determination at Turkey Point Units 3 and 4 Using the LEFM Checkplus^{TM} System," issued June 2010.

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 loss-of-coolant accident and emergency core cooling system (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 √+ System for the measurement of feedwater flow and provide a generic basis for the proposed uprate. The staff also considered the guidance of Regulatory Issue Summary (RIS) 2002-03, "Guidance on the Content of Measurement Uncertainty Recapture Power Uprate Applications," dated January 31, 2002, in its review of the licensee's submittals for the proposed power uprate request. RIS 2002-03 provides guidance on the scope and detail of the information that should be provided to the NRC for reviewing measurement uncertainty recapture power uprate applications.

NRC Technical Evaluation

Background

In existing nuclear power plants, the neutron flux instrumentation continuously indicates the reactor core thermal power. This instrumentation must be periodically calibrated to accommodate the effects of fuel burnup, flux pattern changes, and instrumentation setpoint drift. The reactor core thermal power generated by a nuclear power plant is determined by steam plant calorimetry, which is the process of performing a heat balance around the nuclear steam supply system (called a calorimetric). The accuracy of this calculation depends primarily upon the accuracy of feedwater (FW) flow rate and FW net enthalpy measurements. As such, an accurate measurement of FW flow rate and temperature is necessary for an accurate calibration of the nuclear instrumentation. Of the two parameters, flow rate and temperature, the most important in terms of calibration sensitivity is the FW flow rate.

The originally installed instruments for measuring FW flow rate in existing nuclear power plants were usually venturis or flow nozzles, each of which generates a differential pressure proportional to the FW velocity in the pipe. Of the two, the venturi was the most widely used because of relatively low head loss. However, error in determination of flow rate is introduced

due to venturi fouling and, to a lesser extent, flow nozzle fouling, the transmitter, and the analog-to-digital converter.[41]

Because of the desire to reduce flow instrumentation uncertainty to enable operation of the plant at a higher power while remaining within the licensed rating, the industry assessed alternate flow rate measurement techniques and found that ultrasonic flow meters (UFMs) are a viable alternative. UFMs are based on computer-controlled electronic transducers that do not have differential pressure elements that are susceptible to fouling. Caldon, Inc.,[42] developed a UFM called a "leading edge flow meter" and named it the LEFM Check (√™) system. It followed this with the LEFM CheckPlus (√+ ™) system, which consists essentially of two Check systems in the same spool piece and provides a more accurate FW flow measurement than the Check system. Both of these UFMs have demonstrated better measurement accuracies than the differential pressure type instruments and provide on-line verification to ensure that the UFM is operating within its uncertainty bounds.

Caldon submitted an engineering report, ER-80P (Caldon Inc., "Engineering Report-80P, Topical Report, Improving Thermal Power Accuracy and Plant Safety While Increasing Operating Power Level Using the LEFM√™ System," Revision 0, March 1997), in March, 1997, that describes the LEFM. It includes calculations of power measurement uncertainty using a Check system in a typical two-loop pressurized-water reactor or a two-FW-line boiling-water reactor, and provides guidance for determining plant-specific power calorimetric uncertainties. The NRC staff approved this report as an exemption to the 2 percent uncertainty requirement in Appendix K to 10 CFR Part 50 and approved a 1-percent power uprate for using the LEFM.[43] Following publication of the amendment to Appendix K that allowed for an uncertainty less than 2 percent, Caldon submitted a supplement to ER-80P, ER-160P (Caldon Inc., "Supplement to Engineering Report ER-80P: Basis for a Power Uprate with the LEFM√™ System," ER-160P, Revision 0, May 2000) that the NRC staff approved by letter dated January 19, 2001,[44] for up to a 1.4 percent power uprate. Subsequently, the NRC staff approved ER-157P, Revision 5 for up to a 1.7 percent power uprate using the CheckPlus system[45] and recently approved ER-157P, Revision 8.[46] Revision 8 corrects minor errors in Revision 5, provides clarifying text, and

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[41] "Venturi" will generally be used in the remainder of this document to reference both venturis and flow nozzles.
[42] Caldon Ultrasonics is now part of Cameron Measurement Systems.
[43] Hannon, John N., "Staff Acceptance of Caldon Engineering Report ER-80P: Improving Thermal Power Accuracy While Increasing Power Level Using the LEFM System," NRC letter to C.L. Terry, TU Electric, March 8, 1999 and "Safety Evaluation by the Office of Nuclear Reactor Regulation, Topical Report ER-80P, 'Improving Thermal Power Accuracy and Plant Safety while Increasing Operating Power Level Using the LEFM System,' Comanche Peak Steam Electric Station, Units 1 and 2."
[44] Martin, Robert, "Staff Acceptance of TS Changes, Power Uprate Request, and Caldon Engineering Report ER-160P," NRC letter to J.A. Scalice, Tennessee Valley Authority, January 19, 2001.
[45] Caldon Inc., "Supplement to Engineering Report ER-80P: Basis for a Power Uprate with the LEFM√™ or LEFM CheckPlus™ System," ER-157P, Revision 5, October 2001. Richards, Stuart A., "Review of Caldon, Inc., Engineering Report ER-157P," NRC letter to Michael A. Krupa, Entergy, December 20, 2001.
[46] Estrada, Herb, "Engineering Report 157P, Rev. 8, Supplement to Caldon Topical Report ER-80P: Basis for Power Uprates with an LEFM Check or an LEFM CheckPlus System," Cameron Measurement Systems, ML081720324, May 2008. Non-proprietary version is ML081720323.

incorporates revised analyses of coherent noise, nonfluid delays, and transducer replacement. It also adds two new appendices, Appendix C and Appendix D, which describe the assumptions and data that support the coherent noise and transducer replacement calculations, respectively.

The Office of Nuclear Reactor Regulation's (NRR's) Reactor Systems Branch (SRXB) typically addresses UFM thermal-hydraulics, certain mechanical aspects, and related topics that potentially affect UFM performance. NRR's Instrumentation and Controls Branch (EICB) covers instrument uncertainty and everything from the electrical and mechanical connections at the spool piece to and including the displays that indicate FW flow rate.

The PTN Units 3 and 4 were originally designed with FW flow and temperature instrumentation consisting of venturis, differential pressure transmitters, and thermocouples for each FW header. Modifications required for the MUR portion of the uprate include installation of the CheckPlus system. Existing FW flow and temperature instrumentation will be retained and used for comparison monitoring of the LEFM system and as a backup FW flow measurement when needed.

The FW flow measurement system to be permanently installed is a Cameron LEFM CheckPlus ultrasonic 8-path transit time flowmeter. As discussed above, the CheckPlus design is addressed in Topical Reports ER-80P, ER-160P, and ER-157P that have been approved by the NRC. It will be used for continuous calorimetric power calculation determination by providing FW mass flow and FW temperature input data to the plant computer system that is used for automated performance of the calorimetric power calculations.

The CheckPlus system is stated to consist of one flow element (spool piece) installed in each of the three steam generator (SG) FW flow headers for each unit. The FW piping configurations are stated to have been explicitly modeled as part of the CheckPlus meter factor and accuracy assessment testing performed at Alden Research Laboratories (ARL). The planned installation location of each CheckPlus is stated to conform to the applicable requirements in Cameron's Installation and Commissioning Manual and Cameron Topical Reports ER-80P and ER-157P and the bounding uncertainty analysis is stated to be addressed by ER-783.[47]

The NRC staff reviewed this MUR power uprate based on the LEFM √+ technology and the issued RIS 2002-03, as described below.

Leading Edge Flow Meter Technology and Measurement

Both the Caldon LEFM √™ and LEFM √+ 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

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Hauser, Ernie, "Documentation to support publication of Caldon ER-157P-A Rev. 8," Letter with attachments from Cameron Measurement Systems to NRC, ML102950253 (Package), October 15, 2010.
[47] Hannas, Ryan, et al, "Bounding Uncertainty Analysis for Thermal Power Determination at Turkey Point Units 3 & 4 Using the LEFM√ + System," ER-783 Rev 2, contained in Attachment 8 to ML103560169, June 2010.

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 feedwater 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 √™ 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 √+ System uses 16 transducers, 8 each in two orthogonal planes of the spool piece. In the Caldon LEFM √+ 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 there are 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 instrumentation and controls covers the proposed plant-specific implementation of the feedwater 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 which relates to 10 CFR 50, Appendix K. The staff conducted its review to confirm that the licensee's implementation of the proposed feedwater flow measurement device is consistent with NRC-approved Topical Reports ER-80P and ER-157P and that the licensee adequately addressed the four additional requirements listed below under Item D. 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 50, Appendix K, as described above in the Regulatory Evaluation section.

The licensee provided the information described below regarding the Caldon LEFM √+ System feedwater flow measurement technique and its implementation at PTN Units 3 and 4.

The LEFM systems of PTN Units 3 and 4 contain an individual LEFM metering spool piece on each of the three feedwater flow headers. Each of the LEFM meters functions independently to calculate a feedwater mass flow rate. FPL plans to permanently install the LEFM √+ System in accordance with the requirements of Topical Reports ER-80P and ER-157P and FPL procedures. The system will provide feedwater mass flow and feedwater temperature input

data to the distributed control system (DCS), which is the computer system that automatically performs continuous calorimetric power calculations.

The LEFM √+ 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 communication cables.

The LEFM √+ 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., feedwater mass flow rate and feedwater temperature for each header) and the associated data quality status. The LEFM-based mass flow rate and feedwater 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.

Acceptance Criteria

General acceptance criteria apply to all aspects of testing in a certified facility, transfer from the test facility, initial operation, and long-term in-plant operation. These criteria are:

- Traceability to a recognized national standard. This requires no breaks in the chain of comparisons, all chain links must be addressed, and there can be no unverified assumptions.

- Calibration.

- Acceptable addressing of uncertainty beginning with an initial estimate of the bounding uncertainty and continuing through all aspects of initial calibration in a certified test facility, transfer to the plant, initial operation, and long-term operation.

For CheckPlus, meeting these criteria includes documenting:

- Design and characteristics information,

- Calibration testing at a certified test facility,

- Any potential changes associated with differences between testing and plant operation including certification that initial operation in the plant is consistent with pre-plant characteristics predictions, and

- In-plant operation.

When it originally approved ER-80P and ER-157P, the NRC established four criteria that applicants were to address. In the licensee's LR, the criteria and the applicant responses are as follows (below under Item D of Section License Amendment Request Compliance with RIS 2002-03, Attachment 1, Section I, Items A through H provides more details):

1. Criterion: Discuss maintenance and calibration procedures that will be implemented with the incorporation of the LEFM, including processes and contingencies for inoperable LEFM instrumentation and the effect on thermal power measurements and plant operation.

   NRC Staff Comments: Implementation should include developing the necessary procedures and documents required for LEFM maintenance and calibration. Plant maintenance and calibration procedures should include Cameron's maintenance and calibration requirements prior to declaring the CheckPlus system operational and raising power above approximately 90 percent of the licensed thermal power. Preventive maintenance scope and frequency should be based on vendor recommendations. Maintenance should be performed by personnel qualified on the CheckPlus system. Maintenance and test equipment, setting tolerances, calibration frequencies, and instrumentation accuracy should be accounted for within the thermal power uncertainty calculation. Uncertainty should be at the 95 percent probability and 95 percent confidence level.

   FPL Response: The LEFM CheckPlus system is to be permanently installed in accordance with the requirements of ER-80P, ER-157P, and FPL procedures. Procedures and documents required for operation, maintenance, calibration, testing, and training are discussed. Plant maintenance and calibration procedures will be revised to incorporate Cameron's maintenance and calibration requirements prior to declaring the LEFM system operable and raising power above 98.30 percent. Contingency plans for operation of the plant with the CheckPlus system out of service are described in Section 2.8.7.2.1.6.1, below.

   NRC Staff Assessment: FPL has acceptably addressed Criterion 1.

2. Criterion: For plants that currently have LEFMs installed, 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.

   FPL Response: LEFMs are not installed. Not applicable.

   NRC Staff Assessment: No assessment necessary.

3. Criterion: Confirm that the methodology used to calculate the CheckPlus uncertainty 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.

NRC Staff Comments: The applicant should address the calculation of uncertainty. For example, CheckPlus system uncertainty calculation methodology is usually based on a square-root-sum-of-squares (SRSS) calculation for independent contributors to uncertainty with addition of uncertainties associated with dependent contributors to uncertainty.

FPL Response: FPL stated that (1) the venturi based calorimetric method for determining uncertainty for uprated conditions is consistent with Westinghouse methods, (2) there were no changes in methods implemented for the venturi based calorimetric or uncertainty calculation at the EPU conditions, (3) the CheckPlus calorimetric uncertainty is based on ER-783 and the calculation methods are consistent with the Westinghouse methods with respect to the treatment of individual uncertainties and the statistical combination of terms, (4) inputs used for the Cameron topical report were based on existing plant documentation and are consistent with the venturi based calorimetric uncertainty inputs in the Westinghouse calculation, (5) FPL will make modifications to the plant including blowdown flow and main steam line pressure instrumentation to improve the measurement uncertainty, (6) the methodology used to calculate the uncertainties of the CheckPlus in comparison to the current FW venturis is consistent with accepted plant setpoint methodology, and (7) improvements in measurement of plant parameters for the CheckPlus uncertainty determination are bounded by the methods and assumptions of the Westinghouse uncertainty determination for the venturi based calorimetric.

NRC Staff Assessment: FPL has acceptably addressed Criterion 3.

4. Criterion: For plants where the ultrasonic meter was not installed and flow elements calibrated to a site-specific piping configuration (flow profiles and meter factors not representative of the plant specific installation), additional justification should be provided 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, confirm that the piping configuration remains bounding for the original CheckPlus installation and calibration assumptions.

   NRC Staff Comments: Caldon has always performed pre-installation calibration tests of each CheckPlus at ARL before installation. The tests are performed at room temperature and sometimes at flow rates that are lower than will be obtained in the plant installation. Consequently, the Reynolds Number may differ between the test and plant conditions by approximately a factor of five to ten. This raises the possibility that the flow profile and meter factors (calibration factor) may not be representative of the plant values.

   Criterion 4 allows for installation of a previously calibrated UFM where the calibration was performed at lower Reynolds numbers if acceptable justification is provided. Historically, Caldon has acceptably addressed propagation of flow profile effects at the

higher Reynolds numbers. It also conducts additional confirmatory in-plant tests following installation as part of the final acceptance/commissioning process that provides the final positive confirmation that actual performance in the field meets the uncertainty bounds established for the instrumentation.

The process sometimes involves submission of a pre-test estimate of uncertainties. In Caldon Ultrasonics Engineering Report ER-769, Revision 1 (ML093290054), Cameron addressed the likelihood that testing would fail to confirm the bounding uncertainty parameters. They showed that the meter factor uncertainty was 0.22 percent on the basis of over 94 CheckPlus UFMs subjected to over 2045 calibration tests of over 409 test configurations, with a higher uncertainty of about 0.32 percent for a single meter that was less than 10 pipe diameters downstream of a tubular flow straightener.[48] Typically, without flow straighteners upstream of a CheckPlus, the differences between the pretest bounding uncertainties and post-test uncertainties have been between 0.002 and 0.003 percent with the pre-test uncertainties greater. Consequently, it is unlikely that initial estimates of uncertainties will fail to bound test results.

FPL Response: Criterion 4 does not apply to PTN Units 3 and 4. The calibration factor for the PTN Unit 3 and 4 flow elements has been established by tests of these spools at ARL.

NRC Staff Assessment: This is an acceptable response. FPL provides in-depth coverage of the ARL testing and CheckPlus installation in the plants as reviewed within this safety evaluation.

Test Facility Considerations

Test Facility Qualification

Calibration testing at a qualified test facility and at the plant involves traceability to a national standard and facility uncertainty. On www.aldenlab.com, ARL states that "Alden is the largest independent supplier of National Institute of Standards and Technology (NIST) traceable Flow Meter Calibration Services in the country." The NRC staff audited testing at ARL in 2006[49] and verified ARL's statement with respect to traceablity to NIST. The NRC's audit found that ARL's processes and operation were consistent with the claimed facility uncertainties. The NRC staff also observed testing during a visit to ARL in 2009 and observed some improvements in test facility hardware. The NRC staff judged these changes would not change its previous

[48] There is less experience with flow straighteners upstream of a CheckPlus. SRXB recommends this configuration be avoided because flow straighteners are known to affect CheckPlus calibration. If this configuration is necessary, then the review process must be conducted with an in-depth review of the test and plant configurations and data to ensure the CheckPlus is operating within its stated uncertainty bounds. See Section 2.8.7.2.1.6.6 for an evaluation of this installation configuration specific to Turkey Point: the PTN installation was determined not to have flow straighteners upstream of the UFM.
[49] Lyon, Warren C., "Report of Trip to Alden Laboratory on January 17 and 18, 2006, TAC No. MC8434," NRC Memorandum, ML060400418, February 9, 2006. "Uncertainty Analysis of Flow Measurement 100,000 Lb Weigh Tank," Alden Laboratory, ML072710557, January 17, 2006.

conclusions regarding test operations and results. By two separate letters dated June 2010,[50] Cameron restated that “all elements of the lab measurements are traceable to NIST standards.” Consequently, the references provide an acceptable basis for concluding that ARL meets the stated testing criteria.

All CheckPlus installations to date have been calibrated at ARL. The audit also confirmed that ARL was providing acceptable test data for the configurations under test. Consequently, the qualification of ARL does not need to be investigated further or confirmed with respect to CheckPlus testing provided test conditions remain consistent with the referenced conditions.

Test Fidelity and Test Range

Test fidelity, such as test versus planned plant configuration, test variations to address configuration differences, and potential effects of operation on flow profile and calibration, should be addressed on a plant-specific basis. Applicant requests must provide a comparison of the test and plant piping configurations with an evaluation of the effect of any differences that could affect the UFM calibration. Further, sufficient variations in test configurations must be tested to establish that test-to-plant differences have been bracketed in the determination of UFM calibration and uncertainty. Historically, calibration testing has acceptably covered upstream effects by applying a variation of configurations to distort the flow profile. Further, if the spool piece may be rotated during plant installation from the nominal test rotation, the effect of rotation should be addressed during testing.

Plant piping configuration drawings must, at a minimum, include isometrics with dimensional information that describe piping, valves, FW flow meters, and any other components from the FW pumps to at least 10 pipe diameters downstream of the FW flow meter that is most distance from the FW pump. Preferable are scale three dimensional (3D) drawings in place of isometrics that show this information. Test information must include 3D drawings of the test configuration including dimensions.

ER-748 Revision 1 (ML103560169 - Proprietary) and ER-752 Revision 1 (ML103560169 - Proprietary) provide test configuration drawings and letter dated May 11, 2011 (ML11137A080), provides pipe and instrumentation diagrams and isometrics that show the CheckPlus installation locations. All UFMs are to be installed in 14 inch piping between the 24 inch feedwater header and the downstream feedwater venturis. Distances between the exit of the CheckPlus spool pieces and the downstream elbows in the tests are generally less than distance to the downstream venturis in the plant but in all cases are greater than 7 feet. As discussed below, Evaluation of the Effect of Downstream Piping Configurations on Calibration, this separation distance is large enough that there will be no effect on UFM calibration. Upstream distance between the Tees or reducers that provide a transition between the 24 inch feedwater headers and the 14 inch lines that contain the UFMs is up to about 2 feet less in the tests than in the plant installations and ranges in the tests from about 5 feet to about 13 feet. Although it is desirable to have close correspondence between test and plant geometries, SRXB does not

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[50] Augenstein, Don, “Meter Factor Calculation and Accuracy Assessment for Turkey Point Unit 3 Nuclear Power Plant,” Proprietary, Cameron Measurement Systems, ER-748, Revision 1, contained in Attachment 8 to ML103560169, June 2010.

anticipate these upstream differences will significantly affect the calibrations because they will be bracketed by the effect of geometry variations introduced during the tests. Further, the CheckPlus capability to address changes in flow profile will provide any needed calibration correction as a result of in-plant testing.

Typically, 25 weigh tank tests were run at different flow rates for each simulated feedwater loop. Tests included 100 percent and lower flow rates through the CheckPlus and some tests included an eccentric orifice in the 24-inch feedwater header upstream of the 14-inch feedwater pipes containing the CheckPlus. Most test results were included in the reported main feedwater calculation with an exception being one test in each loop where the eccentric orifice was oriented to introduce swirl, a condition that is stated to not be expected in the plants. However, Cameron stated that “if at the plant the observed swirl rates are substantially different from those in the model calibrations, then these parametric tests may be considered.” The plant qualification tests will address this potential condition.

Meter flow rate data included the 8 and the two 4-path results. This provides a basis for evaluating degraded CheckPlus characteristics.

Transfer from Test to Plant and In-Plant Installation

Each applicant for a power uprate must conduct an in-depth evaluation of the UFM following installation at its plant that includes consideration of any differences between the test and in-plant results and must prepare a report that describes the results of the evaluation. This should address such items as calibration traceability, potential loss of calibration, cross-checks with other plant parameters during operation to ensure consistency between thermal power calculation based upon the LEFM and other plant parameters, and final commissioning testing. The process should be described in written documentation and a final commissioning test report should be available for NRC inspection.

To date, the only UFM calibration traceability associated with transfer from the test facility to United States nuclear power plants that has been acceptably demonstrated is that provided by the Check and CheckPlus UFMs due to the ability to provide the flow distribution/velocity profile as a function of radius and angular position in the spool piece, the small calibration correction necessary to fit test data to UFM indication, and the demonstrated insensitivity to changes in operation associated with transfer changes and plant changes. Although other means have been used to obtain flow rate, such as use of tracers in the feedwater, they have not been demonstrated to provide the small uncertainty obtainable with a CheckPlus. Experience to date is that a UFM must provide flow profile information and calibration traceability when extrapolating from test flow rate and temperature conditions to plant conditions. Transfer uncertainty is associated with any changes due to installation in the plant such as mechanical and operating conditions. Mechanical perturbations include such items as transducer installation, mechanical misalignment, and fidelity between the test and plant. Changes in operating conditions involve consideration of such potential effects as noise due to pumps and valves, changes in flow profile, including swirl, flow rate, and temperature.

As previously identified, the test facility configuration and test parameters are expected to provide a basis for providing fidelity between the test and plant. However, an exact correspondence is probably not possible. Potential differences are expected to have been

addressed and the UFM is expected to provide a capability to both identify differences and to address them during operation.

In its June 2010, letters (ML103560169 (Proprietary) and ML103560169 (Proprietary)), FPL addressed uncertainty. As stated above, the facility uncertainty is acceptable. ER-551 is referenced for transducer installation uncertainty. The content is essentially identical to the October 15, 2010, letter, Appendix D (ML102950253), which the NRC staff found acceptable. Consequently, FPL's treatment of transducer installation uncertainty is acceptable. In Attachment 4 to the LR, FPL stated that "LEFM commissioning will include verification of ultrasonic signal quality and evaluation of actual plant hydraulic flow profiles as compared to those documented during the ARL testing. These parameters will be incorporated as required into the LEFM during commissioning." The NRC staff finds this approach acceptable.

In-Plant Operation

Many of the calibration aspects associated with transfer from a test facility to the plant apply during operation as valve positions change, different pumps are operated, and physical changes occur in the plant. The latter include such items as temperature changes, preheater alignment and characteristics changes, pipe erosion, pump wear, crud buildup and loss, and valve wear. Further, potential UFM changes, such as transducer degradation or failure, may also occur and the UFM should be capable of responding to such behavior. Either the UFM must remain within calibration and traceability must continue to exist during such changes or the UFM must clearly identify that calibration and traceability are no longer within acceptable parameters. Experience is that the CheckPlus is capable of handling these operational aspects. Further, as stated above, UFM operation should be cross-checked with other plant parameters that are related to FW flow rate. Should such checking identify abnormal behavior, it should be identified to the NRC, the validity of the final commissioning test report should be confirmed, and the final commissioning test report should be updated as necessary to reflect the new information. Further, the UFM must be considered inoperable if its calibration is no longer established to be within acceptable limits.

Section I.4 of Attachment 4 to the LR provides coverage of training, calibration, maintenance, procedures, entry into the corrective action program, and procedures to ensure compliance with the requirements of 10 CFR Appendix B. The NRC staff finds the in-plant operation coverage acceptable.

Operation with a Failed Component

A brief description should be provided that covers system self-testing features, channel checks, control room alarms, and plant process computer functions. The following should be addressed to cover conditions if the CheckPlus system becomes degraded or inoperable:

(1) Operator response.

(2) Changes in FW flow input to the core thermal power calculation.

(3) Allowed outage time (AOT)[51] – Time when continued operation at full power is permitted and time when power must be reduced, including specification of the reduced power level.

(4) Justification for the AOT with respect to such topics as calibration of FW venturis, venturi fouling or defouling, monitoring of other indications of core thermal power such as average power range monitors, steam flow rate, feed flow rate, turbine first stage pressure, and main generator output.

(5) Response if the plant computer system is not operable.

Topical Report ER-157P Revision 8[52] states that "the redundancy inherent in the two measurement planes of an LEFM CheckPlus also makes this system more resistant to component failures" when compared to the Check. "For any single component failure, continued operation at a power greater than that prior to the uprate can be justified with a CheckPlus system … since the system with the failure is no less than an LEFM Check." This is acceptable subject to two qualifications:

(1) Continued operation at the pre-failure power level for a pre-determined time and the decrease in power that must occur following that time are plant specific and must be acceptably justified.

(2) The only mechanical difference that potentially affects the quoted statement is that the CheckPlus has 16 transducer housings interfacing with the flowing water whereas the LEFM Check has 8. Consequently, a CheckPlus operating with a single failure is not identical to an LEFM Check. Although the effect on hydraulic behavior is expected to be negligible, this must be acceptably quantified if an applicant wishes to operate as stated. An acceptable quantification method is to establish the effect in an acceptable test configuration such as can be accomplished at ARL.

Section I.5 of Attachment 4 to the LR addresses allowed outage time, monitoring of CheckPlus status, and operational processes associated with a degraded or non-operational CheckPlus. The difference between a degraded CheckPlus and a Check is covered by the ARL test results.

In the below section, "License Amendment Request Compliance with RIS 2002-03, Attachment 1, Section I, Items A through H," operational detail such as allowed outage time, use of alternate plant instrumentation and maximum allowed power levels is discussed.

Planned operation with a failed CheckPlus component is acceptably addressed.

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[51] The NRC has typically approved an AOT of 72 hours if acceptably justified.
[52] Estrada, Herb, "Engineering Report 157P, Rev. 8, Supplement to Caldon Topical Report ER-80P: Basis for Power Uprates with an LEFM Check or an LEFM CheckPlus System," Cameron Measurement Systems, ML081720324, May 2008. Non-proprietary version is ML081720323.

Spool Piece Dimensional Effects on UFM Response

ER-157P, Appendix A, addresses the effect of variation in such spool piece dimensions as as-built internal diameter and sonic path lengths, path angles, and path spacings. The described processes for addressing these effects are acceptable.

Transducer Installation Sensitivity

Transducers may be removed after ARL testing to avoid damage during shipping the spool piece to the plant. Further, transducers may be replaced following failure or deterioration during operation. Replacement potentially introduces a change in position within the transducer housing that could affect the chordal acoustic path. ER-157P, Revision 8, Appendix D addresses replacement sensitivity by describing tests performed at the Caldon Ultrasonics flow loop and provides a comparison of test results to analyses of potential placement variations that shows that the test results are bounded by predicted behavior. One would expect an uncertainty associated with the test loop even if nothing was changed. This is not addressed in the ER-157P information. Rather, all of the test uncertainty is conservatively assumed to be due to transducer replacement. Further, as stated, the analyses predict a larger uncertainty than obtained during testing, and the analysis uncertainty is used for transducer replacement uncertainty. This approach is judged to be sufficient to cover the inability of the test loop to achieve flow rates comparable to those obtained in plant installations and to cover any analysis uncertainty associated with applications with pipe diameters that differ from the tests. Consequently, transducer replacement has been acceptably addressed and the ER-157P process for determining transducer replacement uncertainty is acceptable.

The Effects of Random and Coherent Noise of LEFM CheckPlus Systems

Appendix C of ER-157P, Revision 8 provides a proprietary methodology for test- and plant-specific calculation of the contribution of noise to CheckPlus uncertainty. Review of this methodology has established that applicants may use this methodology in their MUR requests.

Attachment 4 to the LR states that “critical performance parameters, including signal to noise ratio, are continually monitored for every individual meter path and alarm setpoints are established to ensure corresponding assumptions in the uncertainty analysis remain bounding. Signal noise will be minimized via strict adherence with Cameron design requirements. LEFM commissioning will include verification of ultrasonic signal quality.”

Attachment 8 of ER-748, Revision 1 (ML103560169), FPL reported test signal to ratios for random and coherent noise that were within specifications and that “uncertainty attributable to the electronics and signal to noise ratio are included in the overall meter factor uncertainty.”

The test results and the coverage of noise are sufficient to ensure that this topic is acceptably addressed.

Evaluation of the Effect of Downstream Piping Configurations on Calibration

The turbulent flow regimes that exist when the plant is near full power result in limited upstream flow profile perturbation from downstream piping. Consequently, the effects of downstream

equipment need not be considered for normal CheckPlus operation provided changes in downstream piping, such as the entrance to an elbow, are located greater than two pipe diameters downstream of the chordal paths. However, if the CheckPlus is operated with one or more transducers out of service, the acceptable separation distance is likely a function of transducer to elbow orientation. In such cases, if separation distance is less than five pipe diameters, it should be addressed.[53, 54]

As discussed above, the separation is greater than 7 feet and downstream piping components such as elbows and venturis will not affect CheckPlus operation.

Evaluation of Upstream Flow Straighteners on CheckPlus Calibration[55]

Operation with an upstream flow straightener is known to affect CheckPlus calibration to a greater extent than most other upstream hardware. If an applicant proposes this configuration, it must provide justification.

A previously undocumented effect of upstream tubular flow straighteners on CheckPlus calibration was discovered during ARL testing while NRC staff members were at the site on August 24, 2009, that did not appear to apply to any previous CheckPlus installations. As follow-up, additional tests were conducted with several flow straighteners and two different pipe/spool piece diameters to enhance the statistical data basis and to develop an understanding of the interaction between flow straighteners and the CheckPlus. The results are provided in the proprietary version of the March 2010, letter (ML100840026).[56]

[53] This was the case, for example, with a Calvert Cliffs application that the NRC found acceptable (July 22, 2009, ML091820366,). In that installation, the distance between the spool piece exit is 15 inches from the downstream elbow and the chordal paths are 2.7 diameters upstream of the entrance to the piping bend.
[54] Although this is not addressed in ER-157P Rev. 8, it is addressed in the October 15, 2010 (ML102950253), safety evaluation.
[55] This is not addressed in ER-157P Rev. 8 but is addressed in the October 15, 2010 (ML102950253), safety evaluation.
[56] The results do not apply to the Check UFM. Consequently, the findings do not apply to a Check that is installed downstream of a tubular flow straightener.

Cameron concluded that two additional meter factor uncertainty elements are necessary if a CheckPlus is installed downstream of a tubular flow straightener and provided uncertainty values derived from the test results. The data also provide insights into the unique flow profile characteristics downstream of tubular flow straighteners and a qualitative understanding of why the flow profile perturbations may affect the CheckPlus calibration.

Cameron determined that the two uncertainty elements are uncorrelated and, therefore, combined them as the root sum squared to provide a quantitative uncertainty. The Cameron approach is judged to be valid, but there is concern that the characteristics of existing tubular flow straighteners in power plants may not be adequately represented by samples tested in the laboratory. Any applicant that requests an MUR with the configuration as discussed in this section should provide justification for claimed CheckPlus uncertainty that extends the justification provided in the March 2010, letter.

No flow straighteners are installed in the FPL feedwater lines; hence, flow straightener effects are not a concern.

Other Thermal Power Calculation Considerations

Steam Moisture Content

Some modern separators and dryers deliver steam with a moisture content in the 0.05 percent range and these applicants often assume a zero moisture content that is conservative since the calculated power will be greater than actual power for such cases. No uncertainty is necessary if there is no moisture.

Caldon Inc., Supplement to Engineering Report ER-80P: Basis for a Power Uprate with the LEFM√™ System," ER-160P, Revision 0, May 2000, discusses an analysis in which the uncertainty in thermal power due to measurement of all variables excluding moisture is assumed to be normally distributed with two standard deviations of 0.3357 percent, essentially the aggregate uncertainty of all contributors excluding moisture for the CheckPlus system. The contribution of uncertainty due to moisture content was then calculated by multiplying a second, uniformly distributed random number times the uncertainty band assumed in Reference C's Table A-1 and Monte Carlo calculations of total power uncertainty were obtained. The results are summarized in Caldon Inc., ER-160P, Revision 0, May 2000, Figure 1. The author concluded that applicants assuming large uncertainties in steam moisture content should have an engineering basis for the distribution of the uncertainties or, alternatively, should ensure that their calculations provide margin sufficient to cover the differences shown in Figure 1. By letter dated October 15, 2010,[57] it was stated to be an acceptable approach.

The staff provided the following assessment:

> The staff reviewed the uncertainty calculations and issued a request for additional information (ML110070571) regarding the steam moisture carryover assumption and the steam enthalpy uncertainty calculation. In its responses

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[57] Hauser, Ernie, "Documentation to support publication of Caldon ER-157P-A Rev. 8," Letter with attachments from Cameron Measurement Systems to NRC, ML102950253 (Package), October 15, 2010.

> (ML110330190 and ML110330191), the licensee provided its expected (actual) moisture carryover percentage at the PTN steam generator with adequate justification that its assumption is conservative.

Deficiencies and Corrective Actions

The applicant should identify its processes for addressing Cameron deficiency reports and for providing deficiency information to Cameron.

FPL identified its use of updated procedures to be consistent with Cameron documentation governing use of the CheckPlus to cover this area. See the above FPL response to Criterion 1 as an example.

Reactor Power Monitoring

Applicants should identify guidance to ensure that reactor thermal power licensing requirements are not exceeded. By letter dated October 8, 2008 (ML082690105), proposed guidance was addressed by NRC.

EICB provided the following assessment:

> 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.

This statement, the EICB assessment provided in its Items G and H Sections below, and the FPL response to Criterion 1, as summarized above, provides an acceptable description to ensure operation consistent with the October 8, 2008, guidance to prevent overpower operation.

Uncertainty

The following discussion provides information on uncertainty. Cameron considers flow rate uncertainty associated with the test facility, measurement (including transducer installation), extrapolation from test conditions to plant operating conditions, modeling, and data scatter.

Test Facility Uncertainty

The budgeted test facility uncertainty is consistent with past NRC staff evaluations and the value stated in the February 9, 2006, report, “Report of Trip to Alden Laboratory on January 17 and 18, 2006” (NRC Memorandum, ML060400418). The NRC staff finds the uncertainty acceptable.

Measurement Uncertainty

FPL addresses uncertainty due to such contributors as thermal expansion; dimensions; temperature, pressure, and density determination; and transducer installation. The contribution of some of these contributors was discussed in the above report sections. Overall, measurement uncertainty is acceptably addressed.

Extrapolation Uncertainty

Although full flow rate calibration tests were performed, they were conducted at room temperature. This resulted in Reynolds numbers about a factor of ten less than would occur in the plant and an extrapolation is necessary to obtain in-plant calibration factor. A positive aspect of the CheckPlus is that the calibration factor is close to one and small errors in the extrapolation do not significantly affect extrapolation accuracy. Another aspect is that the Check and CheckPlus characteristics permit an alternate extrapolation approach that is typically less sensitive to error than a Reynolds number extrapolation. This involves the flatness ratio (FR), which for the CheckPlus is defined as the ratio of the average axial velocity at the outside chords (chords 1, 4, 5, and 8) to the average axial velocity at the inside chords (chords 2, 3, 6. and 7):[58]

$$\mathrm{FR} = (V_1 + V_4 + V_5 + V_8) / (V_2 + V_3 + V_6 + V_7)$$

where FR is a function of Reynolds number, pipe wall roughness, and the piping system configuration.

The effect of the configuration is evaluated in laboratory tests. The effect of Reynolds number is deduced from the fully developed flow inverse power law profile which may be written in several forms including the following:

$$\frac{V}{V_{max}} = \{X|R\}^{\frac{1}{n}}$$

where X = radial location, R = pipe radius, and the exponent *n* varies with Reynolds number and is determined from experimental data. The advantage of this approach is that a plot of FR versus calibration factor is linear and the calibration factor is insensitive to variation in FR. These results are consistent with analytic predictions and have been confirmed via ARL tests of many plant configurations. Further, minor changes in calibration factor observed in different hydraulics configurations are predictable and can be confirmed analytically. Therefore, if plant conditions result in a change in FR, the calibration factor may be adjusted to reflect the change in FR.

Cameron also uses swirl rate, defined as:

$$\text{Swirl Rate} = \text{Average}\left[\frac{V_1 - V_5}{2 - y_S}, \frac{V_8 - V_4}{2 - y_S}, \frac{V_2 - V_6}{2 - y_L}, \frac{V_7 - V_3}{2 - y_L}\right]$$

where y_S and y_L are normalized chord locations for outside/short and inside/long paths.

Cameron also uses swirl rate to characterize behavior obtained during ARL tests.

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[58] Details of this method are proprietary. This discussion is taken from the non-proprietary report dated June 7, 2004 (ML041760370)

FPL provided experimental data of calibration factor as a function FR and swirl rate for each of the six CheckPlus instruments in its June 2010, letters (ML103560169 (Proprietary) and ML103560169 (Proprietary)), and also provided similar information for six other plants to further substantiate the approach.

Cameron includes an uncertainty term for extrapolation from laboratory conditions to plant conditions that is computed from empirical equations to account for change in Reynolds number and other effects such as a difference in pipe wall roughness. The calibration factor is shown to change in the fifth significant figure over a factor of ten change in Reynolds number between the test and plant conditions. With respect to extrapolation uncertainty, some of the uncertainty was likely already addressed by parametric testing over Reynolds numbers and FRs. FPL neglected this in determining extrapolation uncertainty and then doubled the computed uncertainty to account for potential error in the methodology. FPL has acceptably addressed Reynolds number extrapolation from ARL test results to planned plant conditions by application of the FR approach.

Modeling Uncertainty

Cameron uses FR and swirl rate to characterize the velocity distribution and to validate the experimentally determined calibration factor when installed in a plant. In a paper presented, "Accuracy Validation of Multiple Transit Time Flowmeters," at the 7th International Conference on Hydraulic Efficiency Measurements, Milan, Italy, September 3 - 6, 2008, it discussed application of calibration data obtained at ARL for 330 hydraulic configurations with 75 CheckPlus UFMs with an average calibration factor of 1.002 with a standard deviation of ± 0.0039.

Cameron discussed its experience in calibrating over 127 UFMs with 497 different test configurations since typically 4 or 5 configurations were tested for each UFM. An approach is discussed where more than 150 configurations were considered applicable to the PTN installations and modeling sensitivity was computed using that information.

The FPL method for determining modeling uncertainty is acceptable.

Data Scatter Uncertainty

The precision with which the calibration factor is determined includes all calibration data for each CheckPlus and 95 percent confidence limits are calculated. The FPL determination of data scatter uncertainty is acceptable.

License Amendment Request Compliance with RIS 2002-03, Attachment 1, Section I, Items A through H

<u>Items A through C</u>

Items A, B, and C in Section I of Attachment 1 to RIS 2002-03 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 feedwater flow measurement technique, respectively.

In its LAR, the licensee identified Topical Reports ER-80P and ER-157P as applicable to the Caldon LEFM √+ System. The licensee also referenced NRC SEs dated March 8, 1999, for Topical Report ER-80P, and dated December 20, 2001, 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 √+ System using proper topical report guidelines. Therefore, the licensee's description of the feedwater 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 guides licensees in addressing four criteria that the NRC staff stated in its SEs on Topical Reports ER-80P and ER-157P when implementing the feedwater 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 submittal should 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 stated that implementation of the MUR power uprate 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. The licensee will revise plant maintenance and calibration procedures to incorporate Cameron's maintenance and calibration requirements before declaring the LEFM system operable and raising power above 2,599 megawatts thermal (MWt).[59] Items G and H of this safety evaluation discuss LEFM system maintenance and calibration procedures and contingency plans for operation of the plant with the LEFM √+ System out of service (OOS).

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

(2) For plants that currently have LEFMs installed, provide an evaluation of the operational and maintenance history of the installed 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.

This criterion is not applicable to PTN Units 3 and 4 since the LEFMs are not yet installed.

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[59] The value of 2,599 MWt is based on operation at the requested EPU power level, but without the MUR power uprate provided by the LEFM. Note: Operation at the EPU power level must be specifically approved.

(3) The licensee should confirm that the methodology used to calculate the uncertainty of the LEFM in comparison to the current feedwater 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.

The licensee provided core thermal power measurement uncertainty for the LEFM system at PTN Units 3 and 4. Those uncertainty calculations are based on proprietary Cameron Engineering Report ER-783. The licensee stated that calculation methods are consistent with the methods used by Westinghouse Electric Company with respect to the treatment of individual uncertainties and the statistical combination of terms. Both the Westinghouse and Cameron methods are based on the methods in Instrument Society of America Standard ISA-RP67.04.02, "Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation," issued January, 2000. ER-783 includes uncertainties unique to the LEFM measurement of flow consistent with standard Cameron methodology. FPL makes modifications to the plant, including blowdown flow and main steamline pressure instrumentation, to improve the measurement uncertainty to meet the Cameron uncertainty analysis. The licensee stated that it will perform the post-modification test, which includes verifying LEFM calorimetric calculations using LEFM mass flow and temperatures to ensure LEFM is within established limits (Item 2 in Table 2.12-5 of Attachment 4 to the LAR, ML103560169).

The NRC staff found that the methodology used to calculate the uncertainties of the LEFM in comparison to the current feedwater venturis is consistent with the accepted plant setpoint methodology.

Based on the discussion above and the staff's review of proprietary Cameron Engineering Reports ER-748, ER-752, and ER-783 and 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 flow elements in PTN Units 3 has been established by tests of these spools at Alden Research Laboratory. These tests included a full-scale model of the piping configurations at PTN Units 3 and 4. Cameron Engineering Reports ER-748 and ER-752 for PTN Units 3 and 4, respectively, document the Alden Labs test data and results for the flow elements.

Final verification of the site-specific uncertainty analyses occurs as part of the LEFM √+ 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-748 and ER-752.

Based on the information given above and the staff's review of the licensee's submitted calibration data in Cameron Engineering Reports ER-748 and ER-752, 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 guides licensees in the submittal of a plant-specific total power measurement uncertainty calculation to explicitly identify all parameters and their individual contributions to the power uncertainty.

To address Item E of RIS 2002-03, the licensee provided Cameron Engineering Report ER-783. In addition, the licensee listed each parameter's contribution and the values for the overall thermal power calorimetric uncertainty in Table 2.4.4-1 of Attachment 4 to the LAR. The uncertainties documented in this table are based on Cameron Engineering Reports ER-748, ER-752, and ER-783.

The staff reviewed the uncertainty calculations and issued a request for additional information regarding the steam moisture carryover assumption and the steam enthalpy uncertainty calculation. By letter dated January 28, 2011,[60] the licensee provided its expected (actual) moisture carryover percentage at the PTN steam generator 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 √+ System, as described in the referenced topical reports, and is consistent with the guidelines in Regulatory Guide 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation," issued December 1999.

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.

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[60] ML110330190

Item F

Item F in Section I of Attachment 1 to RIS 2002-03 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:

(1) Maintaining Calibration

The licensee stated that the calibration and maintenance are performed by qualified personnel working under the site work control processes, using site-specific procedures. The licensee will develop the site-specific procedures using Cameron technical manuals. Selected instrumentation and control (I&C) personnel will be trained and qualified in accordance with the Institute of Nuclear Power Operations accredited training program for PTN before maintenance or calibration is performed and before increasing power above 2,599 MWt (Approval to operate at this power level is contingent on the approval of the EPU).

(2) Controlling Hardware and Software Configuration

The Caldon LEFM √+ System is designed and manufactured in accordance with the vendor's quality assurance 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 hardware configuration is controlled on site by the PTN Unit 3 and 4 configuration management program. The LEFM software is controlled on site by the FPL software quality assurance program which is developed to comply with industry standards.

(3) Performing Corrective Actions

Maintenance department I&C personnel, qualified in accordance with the PTN I&C training program and formally trained on the LEFM √+ System, will perform corrective action involving maintenance. The licensee will document and evaluate any conditions that are adverse to quality under the site corrective action program.

(4) Reporting Deficiencies to the Manufacturer

PTN system engineering department personnel will monitor the reliability of the LEFM √+ System. Equipment issues for plant systems, including LEFM √+ System equipment, will fall under the site work control process. Conditions that are adverse to quality will be documented under the corrective action program. Corrective action procedures, which ensure compliance with the requirements of Appendix B to 10 CFR Part 50, include instructions for notification of deficiencies and error reporting.

(5) Receiving and Addressing Manufacturer Deficiency Reports

The PTN Unit 3 and 4 LEFM √+ System will be maintained in accordance with Cameron's verification and validation program, which includes procedures to notify the user of important deficiencies under Cameron's maintenance agreement and reporting requirements under 10 CFR Part 21, "Reporting of Defects or Noncompliance."

The NRC staff's review of the above information found that the licensee addressed the calibration and maintenance aspects of the Caldon LEFM √+ System and all other instruments affecting the power calorimetric. Thus, the licensee has met 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 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.

FPL proposed a 48-hour AOT for operation at any power level in excess of 2,599 MWt with the Caldon LEFM √+ System OOS, provided steady-state conditions persist (i.e., no power changes in excess of 2 percent) throughout the 48-hour period. The 48-hour period begins at the time of the LEFM √+ 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. By letter dated January 28, 2011, 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 % [percent]**	**LEFM Operating Condition**
2644.0	0.30%	System Fully Functional
2640.0	0.42%	One Section (Plane) in any One LEFM in Maintenance
2640.0	0.44%	One Section (Plane) in any Two LEFMs in Maintenance
2639.0	0.47%	One Section (Plane) in all Three LEFMs in Maintenance

Note 1: These values have been truncated to provide conservative values.
Note 2: Additionally, with dual-plane failure of any one of the three LEFM meters OOS, the maximum MWt is limited to 2,599.0 MWt following the 48-hour AOT.

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

- Alternate plant instruments (feedwater venturis, differential pressure transmitters, and resistance temperature detectors (RTDs)) will be used if the Caldon LEFM √+ System is OOS. The mass flow rate data (based on the venturis, differential pressure transmitters, and RTDs) are normalized to the Caldon LEFM √+ System mass flow rate on a periodic basis. This periodic normalization provides a seamless transition at the time of an LEFM OOS condition. During the 48 hours after the failure, the potential contributors to signal error are venturi nozzle fouling and transmitter drift. The licensee stated that the venturi fouling is not a significant contributor to signal error during this period, with the plant at stable full-power conditions. The licensee will periodically monitor and maintain the instruments during the 48-hour period to ensure that transmitter drift will not result in any significant error in the mass flow rate calculation. Therefore, the anticipated instrument drift or fouling over the 48-hour period after failure would not be expected to result in any significant error in the mass flow rate calculation.

- If the plant experiences a power change of greater than 2 percent during the 48-hour period after failure, power level will be restricted to less than or equal to 2,599 MWt until the LEFM √+ System is functional.

- If the automated DCS-based calorimetric power calculation using the LEFMs and alternate instruments were not available, the licensee would perform manual calorimetric calculations in accordance with existing plant procedures. The availability of LEFM output data to support the manual calorimetric is independent of DCS availability (i.e., data can be obtained from the display screens on the LEFM CPUs located in the computer room). Plant administrative procedures will restrict plant power to less than or equal to 2,599 MWt until the automated calorimetric portion of DCS is restored. The event is unlikely since the LEFM system (including the interface to DCS) and the DCS system have been designed to be fault tolerant.

- The configuration of PTN Units 3 and 4 will include separate LEFM flow elements (spool pieces), one for each of the three feedwater headers. These LEFM subsystems (meters) function independently of each other to calculate a mass flow rate for each of the three feedwater headers. As described in ER-157P, each individual LEFM CheckPlus meter consists of two 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.

- The site-specific uncertainty analysis (ER-783) already considers the unavailability of certain redundant subcomponents of the LEFM system (including a single CPU or a single feedwater pressure transmitter). The unavailability of these subcomponents has no adverse affect on the bounding calorimetric uncertainty; therefore, no power limitations will be required.

- If the outage period exceeds 48 hours, then the plant will operate at a power level consistent with the accuracy of the alternate plant instruments. The actions performed for power reduction will be in accordance with operating procedures, such that the plant will operate at or below the specified power limit by the time the 48 hours have elapsed.

The staff reviewed Cameron engineering reports ER-748 and ER-752, which list the meter factors of flow calibration for LEFM√+ normal, plane A, and plane B (i.e. maintenance mode - LEFM√+ with only one transducer plane failed) separately for each flow calibration test at Alden Research Laboratory. The staff found that in effect, each LEFM √+ System meter section is functionally equivalent to the previous generation LEFM √TM meter with the proper meter factor. In accordance with the site-specific uncertainty analysis (Cameron Engineering Report ER-783), failures of one plane of one, two, and three meters result in total calorimetric uncertainties of 0.42 percent, 0.44 percent and 0.47 percent, respectively, as shown in the table above. However, based on the principles of simple decision making and conservative plant operation, the staff determines that only one maintenance mode is acceptable, that is, the plant will be operate as follows:

Maximum MWt	**Total Power Uncertainty %**	**LEFM Operating Condition**
2644.0	0.30%	System Fully Functional
2639.0	0.47%	One Section (Plane) in any Three LEFMs in Maintenance
2599.0	2.0%	Dual-Section (Plane) Failure of any of three 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 found 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.

The licensee has identified the following as an action:

> Verify bounding calibration test data and confirm that actual field performance meets the uncertainty bounds established with the implementation of LEFM CheckPlusTM System and modifications to steam generator blowdown flow and main steam pressure instrumentation (per Item 2 in Table 2.12-5 of Attachment 4 to the LAR).

Conclusion

The NRC staff reviewed the licensee's proposed plant-specific implementation of the feedwater 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 and its supplement Topical Report ER-157P. 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 10 CFR 50, Appendix K and NRC RIS 2002-03. Therefore, the staff concludes that 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

Flood Protection

For proposed power uprates, the Nuclear Regulatory Commission (NRC) staff reviews flood protection measures to ensure that structures, systems, and components (SSCs) important to safety are adequately protected from the consequences of internal flooding. The staff's review in this section evaluates internal flooding events that result from postulated failures of nonseismic equipment.

The plant internal flooding basis was initiated by a 1972 Atomic Energy Commission (AEC) generic communication request to determine whether a failure of non-Category I (i.e., nonseismic) component could result in a flooding condition that could adversely affect equipment necessary for safe shutdown. The licensee had evaluated the consequences of a failure of several non-Category I systems. The degree of plant vulnerability to internal flooding and the design features credited to mitigate or forestall the adverse effects of the flooding were evaluated in a Safety Evaluation Report dated September 4, 1979.

Information on internal plant flooding was included in Appendix 5F, "Plant Internal Flooding," of the Turkey Point Nuclear Plant (PTN) Final Safety Analysis Report (FSAR), "Internal Plant Flooding." This appendix provided a summary of flood protection measures for flooding from pressure-boundary failures affecting non-Category I equipment. The consequences of a component pressure boundary failure in any one of several non-Category I (non-seismic) systems in the turbine building, auxiliary building, and adjacent areas had been evaluated. The non-Category I systems included circulating water, service water tanks, primary water tank, drainage system, and fire protection. Appendix 5F to the PTN Updated Final Safety Analysis Report (UFSAR) describes the protection provided against flooding resulting from failure of non-Category I equipment that could affect the following equipment or locations: diesel generator rooms, residual heat removal (RHR) pump rooms, switchgear rooms, safety injection pumps, motor control centers, charging pumps, containment spray pump rooms, and boric acid, transfer pump rooms, component cooling water pumps, auxiliary feedwater pumps, control room, reactor protection equipment rooms, and battery rooms. The licensee had determined

that certain plant design features, such as the configuration of the plant buildings and the installed elevation of vital equipment, in conjunction with flood mitigation features and capabilities provided sufficient protection to safety-related equipment from the failure of non-Category I components. However, in the case of the RHR pump rooms, an automatic pumping system, high water level alarms, and operator action were credited in protecting the system from flooding. The PTN UFSAR lists the following credited flood mitigation features:

- locating equipment above grade level
- installing safety related equipment on pedestals or providing curbs
- use of floor drainage systems including sumps and sump pumps
- water level alarms
- operator presence and actions
- use of closed doors with water-tight sills (the doors are maintained closed by administrative procedures)
- blocked pipe trenches
- encasement of piping

In Section 2.5.1.1.1.2 of the Extended Power Uprate (EPU) Licensing Report, the licensee evaluated the impacts of EPU-related modifications on flooding resulting from failure of non-Category I equipment. The licensee determined that design features and operational capabilities credited to provide protection from postulated sources of internal flooding would be unaffected by the EPU. The licensee concluded that the performance of structures, systems, and components that are important to safety would remain acceptable and bounded for the EPU because the power uprate would not change the operating and design parameters which formed the basis for the current flooding evaluations. Based on a review of the EPU-related modifications, the internal flood protection analysis described in Appendix 5F to the PTN UFSAR, and the EPU flood protection evaluation presented in Section 5.1.1.1 of the EPU Licensing Report, the NRC staff found that implementation of the EPU would not substantively affect the protection against internal flooding from non-Category I sources.

Equipment and Floor Drains

The function of the equipment and floor drainage system (EFDS) is to provide for the proper routing and control of leakage, and to prevent of backflow of water/contaminated fluids to areas of the plant containing safety-related equipment. In Appendix 5F of the PTN UFSAR, the EFDS is credited with mitigating water accumulation in certain areas of the plant containing safety-related equipment following failures in nonseismic sections of fire protection, circulating water, and service water system piping. The licensee has also identified operational activities to prevent backflow of storm drain water during heavy rains or site flooding though the drain system to certain safety-related equipment rooms. In addition, Section 11.1, “Waste Disposal System,” of the PTN UFSAR describes drains to collect system leakage, and Appendix 9.6A, “Fire Protection Program Report,” describes the provision of drains to collect water from the fire protection systems. The EPU does not affect the operating flow rates, pressures, and component fluid capacities of the service water system, the circulating water system, or the fire protection water system, and the EPU does not affect the need for backflow prevention due to storm water accumulation. Therefore, the EPU does not affect the capability of the floor drains

systems to assist in the prevention of flooding due to breaks in non-Category I systems in or the prevention of backflow of storm water to areas housing safety-related equipment.

Circulating Water System

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove excess heat from the turbine cycle and auxiliary systems. For proposed power uprates, the NRC staff's review of the CWS 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

Internally Generated Missiles

The NRC staff's review concerns missiles that could result from in-plant component overspeed conditions and ruptures of high pressure systems. The purpose of the staff's review is to confirm that SSCs important for event mitigation and plant shutdown are adequately protected from internally generated missiles and that failure of other SSCs will not pose a challenge to those SSCs that are relied upon. The staff's review focuses on system modifications, increases in system pressures, and changes in the operating speed of components that are not bounded by existing analyses.

Regulatory Evaluation

The NRC staff's review concerns the protection of SSCs important to safety from missiles that could result from in-plant component overspeed conditions and ruptures of high-pressure systems. The purpose of the staff's review is to confirm that: (1) SSCs that are important for mitigating accidents that could result in internally generated missiles are adequately protected from the missile effects and (2) SSCs essential for safe shut down are adequately protected from credible missiles. The staff's review focuses on changes in system operating conditions (e.g., increases in system pressure and component overspeed considerations) that could affect missile energy and plant modifications that could introduce new sources of missiles or new SSCs important-to-safety that must be protected from the effects of missiles.

The acceptance criteria that are most applicable to the staff's review of internally generated missiles for the EPU are based on PTN General Design Criterion 40, "Missile Protection," insofar that engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be adequately protected against dynamic effects and missiles that might result from plant equipment failures.

The staff's review related to internally generated missiles is performed in accordance with the guidance provided in Section 2.1, Matrix 5 of the NRC's RS-001, "Review Standard for Extended Power Uprates," December 2003. Acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations for protection of essential components and systems against postulated missiles as discussed primarily in Appendix 5E, "Missile Protection Criteria," of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

NRC Technical Evaluation

The licensee's evaluation of the impact that EPU will have on the consequences of internally generated missiles is provided in Section 2.5.1.2.1 of the EPU Licensing Report. The licensee determined that the operating pressures of systems that could generate missiles inside containment will not increase more than a negligible amount as a result of the proposed EPU. Therefore, missile protection considerations and measures that have been taken for protecting equipment inside containment from the effects of missiles would continue to be valid at EPU operating conditions.

For plant areas containing safety-related SSC's, the licensee determined that changes associated with EPU operation would not result in any changes to existing missile sources or add any new components that could become a new potential missile source. The licensee also determined that changes associated with EPU operation would not result in any system configuration changes that would impact any existing missile barrier considerations.

The staff reviewed the proposed changes and identified modifications for operation at EPU conditions. The condensate and feedwater pumps would be replaced with pumps of similar design (i.e., centrifugal, motor-driven) and located in the same area as the existing pumps. Similarly, certain feedwater heaters would be replaced with heaters of similar design located in the same area as the existing pumps. Finally, the licensee reposed replacing the backup feedwater isolation function performed by the feedwater pump discharge valve with new feedwater isolation valves (FIVs). The new FIVs would be located closer to the feedwater control valves with separate valves for isolation of the main and bypass flow lines, but the valves remain upstream of the feedwater control valves. The PTN UFSAR identified none of the existing components as safety-related components requiring protection from internal missiles, and the replacement components would not be safety-related. Specific missile barriers have been provided for the main feedwater lines from the feedwater control valves to the containment. Otherwise, the existing licensing basis for missile protection has been based on redundancy and separation of safety-related components. Therefore, consistent with the current licensing basis, the replacement of the pumps and feedwater heaters and addition of the new feedwater isolation valves would not affect the design features provided for protection from potential internal missile sources. The staff identified no other modifications with the potential to affect missile protection of safety-related components outside containment.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the EPU and associated modifications would have on potential hazards posed by internally generated missiles. The staff found that SSCs important to safety will continue to be adequately protected

from postulated missiles consistent with the facility licensing basis after EPU implementation. Therefore, the proposed EPU and associated modifications are acceptable with respect to the protection of SSCs important to safety from internally generated missiles.

Turbine Generator

Regulatory Evaluation

The large steam turbines of the main turbine generator (TG) sets have the potential for producing large high-energy missiles, especially if the turbines should exceed their rated speed. Turbine overspeed protection systems maintain turbine speed within design limits. The PTN turbine control system steam inlet stop and 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 acceptance criteria that are most applicable to the staff's review of turbine missiles for the EPU are based on PTN General Design Criterion 40, “Missile Protection,” insofar that engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be adequately protected against dynamic effects and missiles that might result from plant equipment failures.

The staff's review related to internally generated missiles is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations for protection of essential components and systems against postulated missiles as discussed primarily in Appendix 5E, “Missile Protection Criteria,” of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

In addition, Appendix 5E, Section 14.1.13, “Turbine Generator Design Analysis,” of the PTN UFSAR provides a summary of the turbine arrangement, speed control features, and activities related to maintenance of structural integrity. The turbine missiles of concern are potential low-pressure turbine rotor segments that could result from propagation of manufacturing flaws or overspeed ductile failure. The current licensing basis for protection against turbine missiles assures a very low probability of turbine missile generation using a probabilistic analysis to determine the appropriate frequency of turbine-related tests and inspections.

NRC Technical Evaluation

The main turbines at each PTN unit have one high pressure turbine and two low pressure turbines. Steam flows through two stop valves and four governor valves to the high pressure turbine. From the high pressure turbine, the steam is dried and superheated in four moisture-separator reheaters before admission into the low pressure turbines. In addition to the normal speed control using the governor valves, the existing turbine control system includes the following features to limit overspeed:

- a mechanical overspeed trip device set at 111 percent rated speed

- an overspeed protection circuit that uses an auxiliary governor to close the governor and intercept valves at 103 percent rated speed

For the PTN EPU, the licensee proposed replacement of the high pressure (HP) turbine rotor, upgrading to an electro-hydraulic control system that includes different overspeed protection devices, and modifications to the HP turbine control valves for improved steam admission. The licensee stated that the PTN low pressure turbines and the turbine design overspeed and missile generation probability acceptance criteria would be retained for EPU.

The EPU modification to the high pressure turbine increases the energy contained within the turbine following actuation of the turbine overspeed protection system. However, the licensee determined that modifications to the high pressure turbine rotor and main generator would increase the rotational inertia and partially offset the effect of the increased stored energy. The licensee found that these offsetting effects result in only a small increase in the maximum potential overspeed at EPU. Since the 120 percent design overspeed of the unit would not be exceeded with the EPU and associated modifications implemented, no change to the overspeed trip setpoint would be necessary to prevent the design overspeed from being reached.

The licensee determined that the current turbine control valve inspection and test frequency would be unchanged at EPU conditions. The proposed EPU modifications include increasing the travel of the turbine control valves to support higher steam mass flow rates at EPU, but the basic valve design and operation is unchanged. The other turbine overspeed protection system steam valves would remain unchanged at EPU conditions.

The licensee proposed extensive changes to turbine speed sensing, turbine speed control, and overspeed protection system actuation components. In the response to the staff request for additional information dated April 14, 2011,[61] the licensee described that the existing analog control system would be replaced with a digital turbine control system (TCS), the turbine hydraulic control system would be replaced with the standard Siemens electro-hydraulic control (EHC) system, and the existing single mechanical overspeed trip device would be replaced with an independent electric turbine overspeed trip system.

Since the entire turbine control and hydraulic system will be replaced under EPU, the licensee evaluated the change in the failure probability of the control systems by comparing the EPU design for the control and overspeed protection systems against the designs for plants with similar digital electro-hydraulic control (DEHC) and turbine/valve configurations in use at other facilities. The evaluation considered fault tree changes, reliability data for new system components, system redundancy, and other parameters critical to the analysis.

The licensee compared the proposed EPU design against the design of comparable systems at the H. B. Robinson and the Shearon Harris nuclear power plants. The licensee determined that the calculated destructive overspeed missile ejection frequencies for both H.B. Robinson and Shearon Harris were comparable to that of PTN and satisfied the NRC criteria for turbine missile generation presented in NRC Standard Review Plan (NUREG-0800), Section 3.5.1.3. The licensee concluded that the proposed PTN DEHC system would provide increased reliability over the bench mark plants because:

[61] ML11105A146

- The PTN turbine digital control system will have redundancy features that do not exist in the bench mark plants for speed detection and micro processors/power supply/input channel redundancy.

- The PTN EHC system will use the same standard Siemens 6 solenoid trip block as Shearon Harris, which is more reliable than H.B. Robinson design since it has greater redundancy.

In addition, the replacement of the PTN single active mechanical overspeed device with an independent (separate from TCS) fail safe digital control system that has 3 redundant detection channels will improve the overall performance of the PTN overspeed protection system.

The staff found that the identified changes to the turbine overspeed protection system would improve its performance over the existing design. Also, the system provides somewhat greater redundancy in key components than the overspeed protection systems at comparable plants. Since all the evaluated plants have reduced the probability of turbine missile generation to acceptably low values and the proposed Turkey Point turbine overspeed protection system would provide enhanced reliability over the existing system, the staff concluded that, the probability of turbine missile generation is expected to remain acceptably small and consistent with the PTN licensing basis.

Conclusion

The NRC staff has reviewed the licensee's assessment of changes being made to the high pressure turbine, the turbine overspeed protection system, the EPU steam mass flow rate, and other operational characteristics necessary to support the proposed EPU. The staff found that the effect of modifications associated with the EPU on the existing turbine overspeed protection would enhance its performance, and the turbine overspeed protection system will continue to protect the main turbine from excessive overspeed conditions that could result in turbine missile generation, consistent with the existing licensing-basis evaluation. Therefore, the proposed EPU is acceptable with respect to TG overspeed protection considerations.

2.5.1.3 Pipe Failures

Regulatory Evaluation

The failure of high and moderate energy piping can cause pipe whip, jet impingement, and harsh environmental conditions that can result in extensive damage and render SSCs inoperable. For EPUs, the NRC staff's review is concerned with the impact that the proposed power uprate will have on the capability that is credited for mitigating the failure of high and moderate energy fluid piping that is located outside containment and for safely shutting down the plant in accordance with the plant licensing basis. The staff's review focuses on system modifications and increases in system pressures and temperatures that are necessary in order to implement the EPU in order to confirm that the limitations and assumptions of previous pipe failure analyses remain valid or are otherwise addressed.

The staff's review associated with postulated pipe failures is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. The acceptance criteria that are most

applicable to the staff's review of turbine missiles for the EPU are based on PTN General Design Criterion 40, "Missile Protection," insofar that engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be adequately protected against dynamic effects and missiles that might result from plant equipment failures.

Acceptability of the protection against the failure of high energy piping for EPU operation is judged based upon conformance with existing licensing basis considerations. The criteria for the protection of safety related systems from the effects of pipe breaks outside containment were established after issuance of the PTN operating licenses as a result of a request from the AEC by letter dated December 19, 1972 (the Giambusso Letter). The Giambusso Letter contained guidance to perform an evaluation of high energy piping failures entitled, "General Information Required for Consideration of the Effects of a Piping System Break Outside of Containment." This request was further clarified in a subsequent AEC letter from K. Kniel to Dr. J. Coughlin (Florida Power & Light Company (FPL)) dated January 24, 1973, that provided changes and corrections to the guidance. The bases and assumptions for the evaluation of postulated high energy pipe breaks outside containment are based upon the FPL responses to the Giambusso letter and verbal AEC questions provided by letters from Dr. J. Coughlin (FPL) to A. Giambusso (AEC), dated February 26, 1973; March 30, 1973; and June 21, 1973. In these letters, FPL evaluated postulated high energy line breaks outside containment in the following plant systems:

- Main Steam System
- Main Feedwater System
- Auxiliary Feedwater System (Steam Supply)
- Auxiliary Feedwater System (Water Supply)
- Steam Generator Blowdown System
- Chemical and Volume Control System
- Residual Heat Removal System

In these letters, FPL made no licensing basis commitments regarding the analysis of moderate energy line breaks in seismically qualified lines inside or outside of containment. However, internal flooding from certain piping systems was considered, as addressed in Appendix 5F, "Internal Plant Flooding," of the PTN UFSAR. The effect of the EPU on protection from internal flooding was addressed in Section 2.5.1.1, Flooding, Flood Protection, of this safety evaluation.

The evaluation of high-energy pipe breaks outside containment considered zones within the plant which contain systems required for safe shutdown and/or systems required to mitigate the effects of postulated pipe breaks. A pipe break can be postulated in a system which contains fluid during normal operating conditions of greater than 200 °F service temperature and greater than 275 pounds per square inch gauge (psig) design pressure for pipe sizes greater than 1 inch in diameter.

NRC Technical Evaluation

The main turbine generators for each nuclear unit at PTN are supported by an open structure. This structure also supports the portions of the main steam and main feedwater systems and connected systems such as auxiliary feedwater that are outside primary containment. Since a

rupture in any of these systems could not pressurize the open structure, postulated breaks in these systems would not affect the contents of the auxiliary and control buildings.

The licensee evaluated the proposed operation of the high energy systems for EPU operation. The licensee determined that EPU operating conditions would not add any new high-energy piping segments. The staff finds the determination of no new piping segments acceptable because the marginal change in pressure and temperature conditions typically does not result in the development of new, high-energy piping segments.

The effects of the proposed EPU on piping pressure and temperature conditions in the specified systems evaluated for high energy line break generally would be small. For the chemical and volume control system, the steam generator blowdown system, the main steam system, and the steam supply to the auxiliary feedwater pumps, the licensee determined that the EPU operating conditions would be bounded by those conditions assumed in the original break analyses. Therefore, the proposed EPU would have no impact on the results of a pipe failure in these systems.

The effects of the proposed EPU on the main feedwater system would be somewhat greater. The feedwater temperature and pressure increase slightly due to the increased feedwater heating and pressure necessary for the higher EPU feedwater flow rate. As discussed above, environmental effects of feedwater pipe breaks would not be significant because of the open structure supporting the main turbine generator. In the response to the staff request for additional information provided in the attachment to the letter dated April 14, 2011, the licensee described that sleeves and whip restraints had been installed at feedwater system break locations to protect any surrounding safety-related components from the effects of high energy line breaks. Operation at EPU conditions would increase the temperature of the feedwater system a marginal amount (i.e., 0.1 °F to 0.9 °F) at the break locations, and the feedwater pressure would remain bounded by the pressures used in the original analyses. For the modified 6A and 6B feedwater heater outlet piping, the licensee elected to install shields designed to redirect flow from the postulated break location and associated impingement effects in a direction that precludes adverse impact to the safety-related items within the increased zone-of-influence.

Postulated breaks in the water portion of the auxiliary feedwater system would be assumed to be at the same conditions as the main feedwater piping to which it connects. However, the temperature increase is small enough that the temperature at EPU conditions would remain within the rounding assumptions of the break’s dynamic effects calculation. Therefore, there is no impact on the results of a pipe failure in the auxiliary feedwater system.

The staff evaluated the protection afforded to safety-related equipment from postulated breaks in the identified systems relative to the current licensing basis considerations. The staff concluded that there is reasonable assurance that protection from existing postulated pipe break locations would remain acceptable for operation at EPU conditions. The modifications to install shields around the outlet piping of the 6A and 6B feedwater heaters to redirect potential jet effects provides reasonable assurance that safety-related equipment would be acceptably protected from postulated pipe breaks in the new, larger diameter outlet piping. Therefore, the proposed protection against high-energy line breaks would be acceptable for operation at EPU conditions. The staff evaluations of the selection of postulated break locations and the effects of

those breaks are provided in Section 2.2.1 of this safety evaluation. The evaluation of the environmental conditions associated with postulated breaks at EPU conditions is provided in Section 2.6.3 of this safety evaluation. The staff evaluation of environmental qualification of necessary electrical equipment is provided in Section 2.3.1 of this safety evaluation.

Conclusion

Based on the staff review of information provided by the licensee, the staff concluded that the protection from the effects of postulated high-energy line breaks (HELBs)s for structures, systems, and components important to safety would be acceptable because the protection would remain consistent with the original licensing basis. Operation at EPU conditions would be acceptable with respect to the effects of postulated HELBs because the changes in conditions would not materially affect protection from existing postulated breaks and the licensee identified and proposed additional protection from new postulated break locations.

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 shutdown the plant; (2) General Design Criterion 3 (GDC) of Appendix A to 10 CFR Part 50, insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and suppression systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; and (3) GDC 5 of Appendix A to 10 CFR Part 50, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions. Specific review criteria are contained in Appendix D of NUREG-0800, Revision 0, "Standard Review Plan," Section 9.5.1.1, "Fire Protection Program," as supplemented by the guidance provided in Attachment 2 of Matrix 5 of Section 2.1 of RS-001.

The PTN Units 3 and 4 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 Safety Evaluation Report, dated March 21, 1979 and its Supplements, describe the approved fire protection program for PTN Units 3 and 4. The safety evaluation report and supplements are listed in the PTN Units 3 and 4 operating license. In addition to the safety evaluation report and supplements, the PTN Units 3 and 4 fire protection program was evaluated for plant license renewal. The evaluation is documented in NUREG-1759, "Safety Evaluation Report Related to the License Renewal of the Turkey Point Nuclear Plant, Units 3 and 4, dated April 2002.

NRC Technical Evaluation

FPL developed the EPU LAR utilizing the guidelines in RS-001. In the LAR, the licensee evaluated the applicable SSCs and safety analyses at the proposed EPU core power level of 2644 megawatts thermal (MWt). The staff's review of the October 21, 2010, LAR, Section 2.5.1.4., "Fire Protection," Attachment 4, to L-2010-113, identified areas in which additional information was necessary to complete the review of the proposed EPU LAR. In a letter dated February 2, 2011, the staff issued a request for additional information (RAI). By the letter dated February 22, 2011,[62] FPL responded to the NRC staff's RAIs as discussed below.

In RAI AFPB-1.1, the staff noted that RS-001, Attachment 2 to Matrix 5, "Supplemental Fire Protection Review Criteria," states that "power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a fire protection program related to (1) administrative controls, (2) fire suppression and detection systems, (3) fire barriers, (4) fire protection responsibilities of plant personnel, and (5) procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown. In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire. However, the licensee's LAR should confirm that these elements are not impacted by the extended power uprate." The staff noted that license amendment request (LAR), Attachment 4, to L-2010-113, "Licensing Report," Section 2.5.1.4.2.3, on page 2.5.1.4-3, 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 PTN Units 3 and 4, shutdown analysis takes no credit for post fire repair of cold shutdown equipment, except for the replacement of fuses and does not change at EPU conditions. However, review of the shutdown analysis identified one action which could be classified as a "repair." This action involved refilling of the 3B diesel generator day tank from an offsite fuel source for a fire in the Unit 3 emergency diesel generator oil storage tank and surrounding berm area (Fire Zone 90). A fire in this zone could not only affect the diesel oil storage tank for Unit 3 but also the Unit 3 diesel oil transfer pump common header cross connect isolation valves (manual valves 3-70-392A and 3-70-392B, located inside the diesel oil storage tank berm). A fire in Fire Zone 90 which could damage all of these components would prevent refilling of the 3B diesel generator day tank by any other means other than by a fuel truck. The 3B diesel generator day tank is sized to provide fuel for 22.5 hours at rated load. The extended power uprate does not affect the size or minimum technical specification level of the 3B diesel generator day tank, the rated power of the 3B diesel generator, or the manning available or required to support fuel truck refueling operations. Therefore, the procedures and resources necessary for the "repair" of systems required to achieve and maintain cold shutdown are not changed.

The licensee's response satisfactorily addresses the staff's concerns, and this RAI issue is considered resolved based on the following: The licensee indicated that the proposed EPU condition does not affect the procedures and resources necessary for the cold shutdown repairs The safe-shutdown systems and equipment required to transition from hot shutdown and achieve cold shutdown conditions do not change and therefore, procedures and resources to

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achieve and maintain post-fire shutdown are adequate for EPU conditions. Since the elements are not impacted by the EPU, the staff finds the response acceptable.

In RAI AFPB-1.2, the staff noted that LAR, Attachment 4, to L-2010-113, Section 2.5.1.4.2.3.1, on page 2.5.1.4-4, states that, "The impact of plant modifications being implemented in support of EPU on Fire Protection Program will be addressed in accordance with the Plant Change/Modification process …." The staff stated that it is unclear to the staff whether there are fire protection program plant modifications planned (e.g., adding new cable trays, rerouting of existing cables, increases in combustible loading affecting fire barrier ratings, or changes to administrative controls) at EPU conditions.

The staff requested that the licensee clarify whether this request involves plant modifications, or changes to the fire protection program, including any proposed modifications to implement transition to 10 CFR 50.48(c). If any, the staff requested the licensee to identify proposed modifications and discuss the impact of these modifications on the plant's compliance with the fire protection program licensing basis, 10 CFR 50.48, or applicable portions of 10 CFR 50, Appendix R.

In its response, the licensee stated that there are no EPU plant modifications, or changes to the fire protection program, that include proposed modifications to implement transition to 10 CFR 50.48(c). However, for the proposed EPU, several modifications are being implemented that will result in minor changes to combustible loading. These changes are: (1) replacement of pump motors and addition of cabling; (2) upgrade of the main transformer coolers for EPU that necessitates a change to the fire protection system. These changes include redesign of the deluge system piping and relocation of heat detectors. The cooler upgrade also results in a slight increase in combustible loading due to the increase in cooler oil quantity. The changes to the deluge piping, heat detectors and combustible loading have been evaluated and meet current fire protection program requirements; (3) modification of the isophase bus duct for the EPU requires changes to the main transformer, auxiliary transformer, and hydrogen seal oil deluge systems. These changes include deluge piping rerouting, material upgrades, and replacement of the heat actuated devices. Changes to these deluge systems have been evaluated and meet current fire protection program requirements; (4) other plant changes impacting the safe shutdown analysis and fire protection program elements including administrative controls, fire suppression and detection systems, fire barriers, fire protection responsibilities of plant personnel, cold shutdown repair fire protection procedures and resources, fire hazard analysis and primary coolant interfaces. These are evaluated in accordance with the engineering change process to assure continued compliance with the plant's fire protection program licensing basis. The licensee stated that the EPU modifications will not reduce the effectiveness of fire protection for facilities, systems, and equipment that could result in a radiological hazard and will not adversely affect the capability of existing fire protection features and safe shutdown following a fire. The EPU modifications will not result in adverse changes to the fire protection program's compliance with 10 CFR 50.48, or post-fire safe-shutdown capability.

The licensee's response satisfactorily addresses the staff's concerns, and this RAI issue is considered resolved based on the following: For the EPU condition, the licensee indicated that there are no changes to the fire protection program to implement 10 CFR 50.48(c). Further, the licensee identified that the EPU conditions result in changes to combustible loading (additional

cable) due to replacement of a pump motor. Other changes are upgrading of the main transformer cooler and redesign of deluge system piping, relocation of heat detectors, modification to the main and auxiliary transformer, and hydrogen seal oil deluge system. The licensee stated that these changes in combustible loading were evaluated and determined to have no impact on the existing fire protection features and post-fire safe shutdown capability. Since these changes do not impact fire protection features or post-fire safe-shutdown capability, the staff finds the response acceptable.

In RAI AFPB-1.3, the staff noted that Attachment 4 to L-2010-113, Section 2.5.1.4.2.3.2, on page 2.5.1.4-8, “Time Critical Manual Action Evaluation,” identifies some additional Fire Zones, 84 and 106, requiring operator manual actions as a result of EPU. Section III.G.3 of Appendix R addresses alternative or dedicated shutdown capability independent of the fire area of origin and establishes a series of requirements to achieve and maintain safe shutdown capability. The staff requested the licensee to confirm that the compliance strategy for Fire Zones 84 and 106 is consistent with Appendix R, Section III.G.3.

In its response, the licensee stated that the compliance strategy for Fire Zone 106 (main control room) is consistent with III.G.3. The compliance strategy for Fire Zone 84 (Unit 3 and Unit 4 auxiliary feedwater pump area) is not consistent with III.G.3. Though Fire Zone 84 uses compliance strategy III.G.2 versus III.G.3, no additional operator manual actions were identified as a result of the EPU. The thermal-hydraulic analyses performed for EPU demonstrated that sufficient time remains available to satisfy requirements for all actions taken in the PTN safe shutdown analysis, given the post-EPU plant conditions (i.e., actions are still feasible).

The licensee’s response satisfactorily addresses the staff’s concerns, and this RAI issue is considered resolved based on the following: The licensee clarified compliance strategies for Fire Zones 84 and 106. The licensee stated that no additional operator manual actions are required as a result of the EPU, therefore, the staff finds the response acceptable. Note that this safety evaluation does not approve any new or existing operator manual actions concerning PTN fire safe shutdown analysis.

In RAI AFPB-1.4, the staff noted that Attachment 4 to L-2010-113, Section 2.5.1.4.2.3.2, on page 2.5.1.4-9, “Time Critical Manual Action Evaluation,” states:

> Prior to EPU, the PORV is required to be closed before leaving the Control Room and are verified closed from the Alternate Shutdown panel (ASP) within 15 minutes. Opening of these PORV breakers will be additional actions added to an already assigned position and are to be completed within 5 minutes at the local dc panel ….”

The staff requested the licensee to discuss why opening of PORV breakers, which will be additional actions added to an already assigned staff position requiring completion within 5 minutes at the local dc panel, should be considered acceptable.

In its response, the licensee stated that the decision to add the actions to open additional dc breakers was made based on a qualitative risk versus gain evaluation of the plant parameters, independent of extended power uprate evaluations. The decision was made because the actions (a) provide defense-in-depth for the mitigation of this potential spurious operation

without hindering safe shutdown and (b) the opening of two additional dc breakers in distribution panels accessed by the procedure has little impact on the timing, training, and reliability of the existing procedure. The existing plant actions to close the PORV block valve prior to control room evacuation and isolate PORV and PORV block valve control circuits within 15 minutes at the alternate shutdown panel meet regulatory requirements and provide adequate assurance that core damage will not occur following the PTN extended power uprate.

Generic Letter 86-10, Section 3.8.4, “Control Room Fire Considerations,” allows plants to take actions in the control room prior to evacuation. These actions require assurance that they could not be negated by subsequent spurious actuation signals resulting from the postulated fire. PTN's control room evacuation procedure identifies actions to be taken (if possible) prior to leaving the control room (including closing the PORV block valves to isolate the PORV flowpath). The procedure also directs actions at the alternate shutdown panel to isolate PORV and PORV block valve circuitry from the area with the fire. These actions satisfy the requirements imposed by the generic letter; furthermore, the actions to open DC breakers at the local distribution panel provide additional assurance that the existing plant procedure will prevent the control room action from being negated by spurious operation of the PORV until actions are performed at the alternate shutdown panel.

In an email dated May 19, 2011, the staff issued a follow-up RAI to the licensee to clarify time critical manual action, i.e., addition of a new step in the control room to prevent spurious operations of the PORVs prior to evacuation from the control room.

By letter dated June 9, 2011,[63] the licensee stated that the opening of two additional dc breakers will be incorporated into the existing procedures to prevent any spurious opening of either of these PORVs. The addition of the dc breakers to the list of breakers to be opened at each of the dc distribution panels above is expected to add no more than a few seconds to the current action completion time. These breakers are not being incorporated into the procedure as a result of the EPU but rather as an enhancement to the defense in depth provisions in the procedure for response to a fire in the main control room.

The licensee’s response satisfactorily addresses the staff’s concerns, and this RAI issue is considered resolved based on the following: The licensee clarified that at EPU conditions opening of PORV breakers, which will be additional actions added to an already assigned staff position requiring completion within 5 minutes at the local dc panel, should be considered acceptable. The licensee indicated that it will mitigate the potential spurious operation and opening of additional dc breakers in distribution panels, which has little impact on timing training, and reliability of the existing procedure. Overall, this provides adequate assurance that core damage will not occur following the PTN extended power uprate.

In RAI AFPB-1.5, 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 nonprimary reactor systems. If the PTN Units 3 and 4, credit their fire protection systems in this way, the staff requested that the licensee identify the specific situations and discuss to what extent, if any, the extended power uprate and measurement uncertainty recapture affect these “nonfire protection” aspects of the plant fire protection system.

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If the PTN Units 3 and 4 do not take such credit, the staff requested that the licensee verify this as well. The staff further requested that the licensee discuss how any nonfire 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 PTN Units 3 and 4 do not use or credit fire water pumps or dedicated supply for nonfire protection functions during normal plant operation. The licensee identified the following four provisions to use the fire protection system for nonfire suppression functions during off-normal or emergency conditions: provide make up to the condensate storage tank, refueling water storage tank, containment, and spent fuel pool. Further, the licensee stated that the provisions for using fire water for off-normal or emergency evolutions are not changed as a result of EPU.

In an email dated May 19, 2011, the staff issued a followup RAI to the licensee to clarify (1) how the capabilities of the fire water supply is met if a fire event occurs during off-normal or emergency conditions and (2) to further clarify how fire protection hydraulic demands (fire suppression system water flow demands) are met.

In a letter dated June 9, 2011, the licensee stated that fire water may be used for nonfire applications and that there are procedural controls and guidance for doing so. This capability allows for plant operational flexibility in responding to off-normal and beyond design basis events as directed in the severe accident management guidelines. The licensee stated that the PTN licensing basis does not require that design basis fires be assumed during beyond design basis events. The licensee further stated that the fire water supply system contains significant flow margin such that this flexibility does not compromise hydraulic demands required for fire protection.

The licensee stated that fire water makeup to the condensate storage tanks, refueling water storage tanks, containments and spent fuel pools is only required when normal makeup sources are unavailable. For off-normal conditions, the maximum makeup flow requirement is ~100 gallons per minute (gpm), and for beyond design basis events the maximum flow requirement is ~500 gpm.

The licensee stated that hydraulic flow testing of the fire protection system has demonstrated at least 700 gpm of margin above the maximum flow demand to address fire protection requirements as defined in UFSAR Appendix 9.6A Section 3.1.3. This margin bounds the maximum nonfire protection makeup flow requirements for off-normal and beyond design basis events described above. The licensee concluded that fire protection hydraulic demands are met even under conditions where the fire water system is supplying the maximum nonfire protection makeup flow for off-normal or beyond design basis conditions.

The staff reviewed the licensee clarification on use of fire protection water/systems for nonfire protection functions, including whether such use could impact the need to meet the fire protection system design demands. The staff finds the licensee’s response to the RAI acceptable because (1) the nonfire protection uses of the fire protection water supply do not occur during normal plant operation, and (2) the licensee’s analysis concluded that all four functions of nonfire suppression uses of fire protection water are not affected by the proposed EPU.

Based on the licensee's fire-related safe-shutdown assessment and responses to the RAIs, the staff concludes that the licensee has adequately accounted for the effects of the 15 percent increase in decay heat on the ability of the required systems to achieve and maintain safe-shutdown conditions. 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 2644 MWt acceptable with respect to fire protection.

Conclusion

Based on its review, the NRC staff has concluded that the proposed EPU will not have a significant impact on the fire protection program or post-fire safe shutdown capability and, therefore, finds the proposed amendment acceptable.

2.5.2 Pressurizer Relief Tank

Regulatory Evaluation

The pressurizer relief tank (PRT) is a pressure vessel provided to condense and cool the discharge from the pressurizer safety valves and PORVs. The tank is designed with a capacity to absorb discharged fluid from the pressurizer relief valves during a specified step-load decrease. The PRT system is not safety related and is not designed to accept a continuous discharge from the pressurizer. The purpose of the review is to confirm that operation of the PRT will continue to be consistent with the transient analysis of the RCS following implementation of the proposed power uprate, and that failure or malfunction of the PRT will not adversely affect safety-related SSCs. The staff's review focuses on any modifications to the PRT and connected piping, and changes related to operational assumptions that are necessary in support of the proposed EPU.

In general, the steam condensing capacity of the tank and the tank rupture disk relief capacity should be adequate, taking into consideration the capacity of the pressurizer power-operated relief and safety valves; the piping to the tank should be adequately sized; and systems inside containment should be adequately protected from the effects of high energy line breaks and moderate energy line cracks associated with the pressurizer relief system. The acceptance criteria that are most applicable to the staff's review of the PRT for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC 4, insofar as SSCs important to safety should be designed to accommodate and be compatible with specified environmental conditions and be protected against dynamic effects, including the effects of missiles; and other licensing-basis considerations that apply. The corresponding PTN GDC 40, states:

> Adequate protection for those engineered safety features, the failures of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failures.

The staff's review of the PRT is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability of the PRT for EPU operation is judged based upon conformance with existing licensing basis considerations as discussed primarily in

Section 4.2.2, "Components," of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

NRC Technical Evaluation

The licensee's evaluation of the impact that the EPU will have on the capability of the PRT to continue to provide adequate relief capacity following a maximum expected pressurizer pressure discharge condition is provided in Section 2.5.2 of the PTN EPU Licensing Report. Section 4.2.2 of the PTN UFSAR describes that the rupture discs on the PRT have a relief capacity greater than the combined capacity of the pressurizer safety valves. Since the installed capacity of the pressurizer safety valves is unchanged for EPU operation, the PRT remains adequately protected against failure due to over-pressurization.

Section 4.2.2 of the PTN UFSAR states that the PRT is sized to receive and condense a discharge of 110 percent of the full-power pressurizer steam volume. In Section 2.5.2 of the EPU Licensing Report, the licensee described that the PRT size was selected to ensure the tank could accept the discharge from the pressurizer safety valves following the worst case loss of external load transient. In the EPU Licensing Report, the licensee described the assumptions and methodology used to evaluate the loss of external electrical load transient without a direct reactor trip. The analysis for EPU demonstrated that the mass and energy of the steam discharged from the pressurizer into the PRT is less than the design bases discharge used for PRT sizing. Therefore, the licensee adequately demonstrated that the PRT has the capacity to absorb the steam release associated with a complete loss of electrical load. This capability satisfies the guidance provided in Section 2.1 of RS-001, Matrix 5, and is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the PRT to perform its design function. The PRT will remain capable of condensing and containing steam that is discharged from the pressurizer safety valves, and safety-related SSCs will continue to be adequately protected from PRT failures due to over-pressurization following postulated transient and accident conditions, consistent with the PTN licensing basis and NRC staff guidelines. Therefore, the proposed EPU is acceptable with respect to the PRT.

2.5.3 Fission Product Control

Fission Product Control Systems and Structures

The purpose of the NRC staff's review of fission product control systems and structures is to confirm that current analyses remain valid or have been revised, as appropriate, to properly reflect the proposed EPU conditions. Consequently, the staff's review focuses primarily on any adverse effects that the proposed EPU might have on the assumptions that were used in the analyses that were previously completed. Because the impact of EPU on plant and structures identified by the licensee as making up the fission product control system, such as the containment spray 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 safety evaluation, a separate review of this area is not required.

Main Condenser Evacuation System

As described in PTN UFSAR Section 10.2.5, “Radioactivity,” under normal operating conditions, there are no radioactive contaminants present in the steam and power conversion system unless steam generator tube leaks develop. Monitoring of the main condenser evacuation system (MCES) would detect any contamination and permit calculation of activity release to the atmosphere. High radiation levels in this pathway are detected, indicated, and alarmed in the control room. The MCES would not be impacted by the proposed power uprate because the condenser air removal requirements remain within the capacity of the existing system. Consequently, the existing capability to monitor the MCES effluent is also not affected by the proposed EPU and, therefore, detailed NRC review of the MCES is not required.

Turbine Gland Sealing System

As described in PTN UFSAR Section 10.2.5, “Radioactivity,” under normal operating conditions, there are no radioactive contaminants present in the steam and power conversion system unless steam generator tube leaks develop. Monitoring of the MCES would detect any contamination and permit calculation of activity release to the atmosphere. High radiation levels in this pathway are detected, indicated, and alarmed in the control room. The turbine gland sealing system (TGSS) prevents air leakage into the turbine casing and prevents steam leakage from the turbine casing into the turbine building. The TGSS has not been monitored for radioactive effluents and the continued monitoring of the MCES would remain adequate for operation at EPU conditions. Accordingly, NRC review of the TGSS for EPU is not necessary.

2.5.4 Component Cooling and Decay Heat Removal

Spent Fuel Pool Cooling and Cleanup System

Regulatory Evaluation

The spent fuel pool cooling and cleanup system (SFPCCS) provides cooling for the spent fuel assemblies and keeps them covered with water during all storage conditions. The NRC staff’s review for proposed power uprates focuses on the capability of the SFPCCS to accommodate the additional heat load that will result from EPU operation in accordance with the SFPCCS licensing basis. The GDCs that are most applicable to the staff’s review of the SFPCS for the PTN EPU are GDC 44, “Cooling Water,” insofar as it specifies 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 GDC 61, “Fuel Storage and Handling and Radioactivity Control,” insofar as it specifies that fuel storage systems be designed with residual heat removal capability that is commensurate with the safety function being performed.

At PTN, the SFPCCS is known as the SFPCPS. The design criteria used during licensing of PTN predate those provided in 10 CFR Part 50, Appendix A. The PTN design criteria were developed based on the 1967 Atomic Energy Commission Proposed General Design Criteria. There is no specific PTN design criterion analogous to GDC-44 on Cooling Water that requires

a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under normal operating and accident conditions. However, PTN GDC-67, "Fuel and Waste Storage Decay Heat," states:

> Reliable decay heat removal systems shall be designed to prevent damage to the fuel in storage facilities and to waste storage tanks that could result in radioactivity release which could result in undue risk to the health and safety of the public.

The staff's review of the PTN SFPCPS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5, and acceptability is based on conformance with the licensing basis. The SFPCPS licensing basis, including design features, operating modes, cooling capabilities, pool temperature limits, and failure modes, is described in Section 9.5.3, "Spent Fuel Pit Cooling and Purification," of the PTN UFSAR.

NRC Technical Evaluation

Section 9.5.3, "Spent Fuel Pit Cooling and Purification," of the PTN UFSAR described that the spent fuel pit cooling loop is designed to remove residual heat from the fuel assemblies stored in the high-density storage racks contained within the spent fuel pit. The SFPCPS design and operation is unit specific and does not share any of its components or functions between units. The cooling loop for each unit is capable of removing the decay heat from 1535 assemblies (1404 assemblies in the spent fuel pit (SFP) storage racks and, when installed, up to 131 assemblies stored in the cask area rack).

The SFP cooling loop consists of two pumps in parallel, one heat exchanger, filters, demineralizer, piping and associated valves and instrumentation. However, because both pumps are fed from the same breaker, only one pump can be operated at a time. The operating pump draws water from the SFP, circulates it through the heat exchanger and returns it to the SFP. Component cooling water cools the heat exchanger. Component data for the SFPCPS is provided in UFSAR Table 9.5-16.

The licensee classifies the SFPCPS as safety-related and seismically qualified, but the existing SFPCPS does not meet the standard redundancy and reliability requirements of a safety-related system. The existing system would be lost following a failure of the single power supply, and the licensee does not consider the system operable after loss-of-offsite power. Thus, the system design basis allows for the pool to heat up and boil. By the time the pool heats up, the licensee credits alignment of available makeup sources to the pool to offset inventory loss. The cooling loop has been analyzed and designed to remain functional during and following a seismic event and to structurally withstand a design temperature of 212 °F.

The PTN UFSAR describes the following SFP temperature limits for the SFPCPS:

- the temperature in the SFP is less than or equal to 150 °F during all planned refueling operations.

- the bulk maximum SFP temperature will remain below 212 °F during an unplanned offload evolution.

The licensee's evaluation of the impact that the EPU will have on the capability of the SFPCPS to continue to provide adequate cooling considering the additional heat load is provided in Section 2.5.4.1 of the PTN EPU Licensing Report. In order to ensure that current spent fuel pool (SFP) design limits can be maintained, the licensee proposed the addition of a supplemental SFP cooling heat exchanger to the cooling loop for each unit. The supplemental heat exchanger would provide a minimum increase of 30 percent in cooling capacity relative to the current cooling system capacity. In addition, the licensee proposed to independently power the SFP pump motors through separate breakers instead of from the same source through a transfer switch, thereby allowing simultaneous or independent operation for maintenance and operational flexibility.

The licensee stated that the modified SFPCPS will remain functional during and after seismic events and will continue to be able to maintain structural integrity assuming a SFP water temperature of 212 °F. System modifications to enhance refueling heat removal capability will meet seismic requirements. The system would still be considered safety-related, but it would not be fully redundant, nor would the pumps load onto the emergency diesel generators in the event of a loss-of-offsite power. Therefore, the current licensing and design basis that allows the SFP water to boil in the event that cooling is lost would be retained, and adequate makeup water must be maintained available to offset evaporative losses and maintain the required water level above the spent fuel in the pit.

Operation at EPU conditions would increase the heat load within the SFP. The licensee used the following considerations in evaluating the heat load change:

- EPU decay heat calculations account for the increase in core thermal power to 2652 MWt, the higher initial fuel enrichment for EPU operation, and the higher fuel assembly burn-up at EPU operating conditions.

- Decay heat would be determined for the SFP at full capacity assuming recently discharged assemblies and all previously discharged assemblies were operated at EPU operating conditions.

- EPU operations would increase reload batch size from nominally 1/3 core to 72 fuel assemblies.

The licensee reevaluated the peak SFP temperatures for several design cases included in the PTN UFSAR. The first design cases involved planned full core discharges beginning at 72 hours after reactor shutdown. Case 1a assumed an 85 °F component cooling water temperature with a fuel transfer rate of 8 assemblies per hour, and Case 1b assumed a 105 °F component cooling water temperature with a fuel transfer rate of 6 assemblies per hour. For case 1a, the increase in the decay heat associated with the EPU and the improved performance of the SFPCPS resulted in a decrease in the peak SFP temperature from 147 °F to 142 °F. The peak SFP temperature at the maximum CCW temperature of 105 °F (Case 1b) would also be lower than the existing result, but both the current and post-EPU results exceed the acceptance criterion of 150 °F. However, as stated in the UFSAR, the licensee may perform analyses to determine a cycle-specific off-load start time and fuel assembly off-load rate in lieu of the bounding restrictions in order to assure the SFP temperature does not exceed 150 °F. Case 2

involves a planned partial core offload case, which is not limiting with respect to SFPCPS design. The staff found the evaluation of SFPCPS performance for planned refueling conditions was consistent with the expected effects of the proposed modifications and satisfied the acceptance criteria associated with the existing licensing basis of the system. Therefore, proposed EPU operation with the enhanced cooling capability would provide acceptable reliability of decay heat removal for normal operating conditions.

The increased heat load resulting from the EPU also affects the spent fuel pool heat-up rate in the unlikely event of a total loss of cooling. For PTN, the shortest time for the pool to heat to boiling following a total loss of cooling was associated with an unplanned full core offload 36 days following shutdown for a planned refueling (PTN UFSAR Case 3). As for the planned refueling cases, the improved cooling capability out-weighed the EPU-related increase in decay heat resulting in a decrease in the peak SFP temperature from 183 °F to 177 °F. The licensee determined that, with the lower peak SFP temperature, the time to heat to boiling would increase from 1.5 hours to 1.6 hours after the EPU-related changes. Therefore, the proposed post-EPU conditions increase the time available to align a make-up water sources under the most limiting conditions and, therefore, continue to satisfy the existing licensing basis with regard to timely provision of makeup water.

The licensee determined that the pool make up water supply rate necessary to maintain water level at the maximum decay heat load associated with PTN UFSAR Case 3. The necessary make up water supply rate would increase from 80.7 gpm to 96.5 gpm. However, the available make up water supply rate from the refueling water storage tank (borated water), the demineralized water system, the primary water system (direct connection or local hose station), and the fire hose station outside the spent fuel pit area could all provide a minimum of 100 gpm. Therefore, there would be several make-up sources available to maintain spent fuel pit cooling water level following a complete loss of cooling at EPU operating conditions. This capability remains consistent with the licensing basis provided in the PTN UFSAR, which states that, in the event of complete failure of the cooling system for a long period of time, the fuel pool water inventory can be maintained. Thus, the ability to provide adequate residual heat removal through provision of sufficient make up water to prevent a significant reduction in spent fuel pool coolant inventory under accident conditions would be maintained at the EPU power level.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the capability of the SFPCCS to perform its safety function and finds that the SFPCPS would remain capable of maintaining the spent fuel pool below the maximum specified temperatures in accordance with licensing-basis assumptions. Also, the licensee would retain sufficient time to provide make up water and adequate capacity to prevent a significant reduction in spent fuel pool coolant inventory under accident conditions. Therefore, the proposed EPU is considered to be acceptable with respect to the spent fuel cooling licensing basis and the applicable requirements of PTN GDC 67.

Station Service Water System

Regulatory Evaluation

The station service water system (SWS) provides essential cooling to safety-related equipment. The SWS also provides cooling to nonsafety-related auxiliary components that support normal plant operation. The NRC staff's review covered the functional performance of the SWS under the additional heat load that would result from the proposed EPU with respect to adverse operational conditions, abnormal operational conditions, and accident conditions (such as a loss-of-coolant accident (LOCA) with loss-of-offsite power).

The acceptance criteria that are most applicable to the staff's review of the SWS for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC-4, "Environmental and Dynamic Effects Design Bases," 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 GDC 44, "Cooling Water," insofar as a system should be provided with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions.

At PTN, the SWS is known as the intake cooling water (ICW) system. The design criteria used during licensing of PTN predate those provided in 10 CFR Part 50, Appendix A. The PTN design criteria were developed based on the 1967 Atomic Energy Commission Proposed General Design Criteria. There is no specific PTN design criterion analogous to GDC-4 for the service water system to be compatible with environmental conditions associated with normal operation and postulated accidents. Similarly, there is no specific PTN design criterion analogous to GDC-44 on Cooling Water that requires a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under normal operating and accident conditions. However, the design of the ICW system incorporates capabilities consistent with these design criteria.

The licensee implemented a program to manage the effects of loss of material due to various corrosion mechanisms and biological fouling for ICW system components that includes inspections, performance testing, evaluations, and corrective actions. The licensee developed this program as a result of commitments made on January 30, 1990 in response to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The NRC found the licensee's commitments acceptable and notified the licensee of that finding by letter dated March 23, 1990.

The staff's review of the PTN ICW system is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability for EPU operation is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.6.2, "Miscellaneous Water Systems," of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

NRC Technical Evaluation

The ICW System is described in UFSAR Section 9.6.2. The ICW System provides cooling water to the safety-related CCW heat exchangers and to the nonsafety-related turbine plant cooling water (TPCW) heat exchangers. A separate ICW System is provided for each nuclear unit.

Each Unit's ICW System consists of three ICW pumps, tie headers, two independent supply headers, piping, valves, and basket strainers. Two pumps are normally operated to remove system heat loads. The ICW System provides sufficient redundancy so that at least one ICW pump will continue to operate to handle heat loads from design basis accidents following a postulated single active failure. The flow provided to the nonsafety-related TPCW heat exchangers is automatically isolated upon receipt of a safety-injection actuation signal that closes ICW supply valves to the heat exchangers.

The licensee's evaluation of the impact that the EPU will have on the capability of the ICW system to continue to provide essential cooling water to the CCW heat exchangers is provided in Section 2.5.4.2 of the PTN EPU Licensing Report. The licensee determined that the existing minimum required ICW flow rate to the CCW heat exchangers of 15,200 gpm would remain acceptable for removal of postulated accident heat loads at EPU operating conditions. Therefore, ICW system would remain capable of providing this flow rate with the most limiting single failure scenario of one pump supplying two CCW heat exchangers, and the existing system operating pressure would remain adequate to deliver the required flow. The licensee determined that the existing flow rates do not require revision because the results of both the containment accident and CCW thermal performance analyses were found to be acceptable. However, accident mitigation and plant cooldown operations, which are directly affected by decay heat levels, would result in higher ICW discharge temperatures and increased time to reach specific plant conditions. The licensee stated that higher peak accident temperatures in systems cooled by ICW would be addressed through piping modifications where necessary. Thus, the ICW temperatures and pressures at the EPU power level would be acceptable for normal operating and accident conditions.

Existing programmatic controls established in response to GL 89-13 remain in place and continue to assure that heat exchanger performance is consistent with design-basis assumptions. In an Attachment to a letter dated April 14, 2011,[64] the licensee responded to a staff request for additional information regarding the effect of the higher CCW temperatures on the CCW heat exchanger performance due to the potential for increased scale formation. The licensee evaluated the effects of higher CCW temperatures and increased salinity on the potential for scaling. The licensee determined that the approximately 4-hour period post-accident that CCW temperature would exceed 150 °F would not significantly affect scale formation and the increased salinity would not directly affect scale formation. The licensee explained that the decreased CCW heat exchanger tube resistance used for EPU accident analyses adequately considered the water qualities associated with a higher percentage salinity including density, viscosity, specific heat and thermal conductivity. Based on these evaluations, the licensee concluded that the surveillance and testing procedures would be adequate to maintain the level of cleanliness required by the EPU analyses and that the ICW system would

[64] ML11105A146

continue to satisfy its safety functions without the need for modifications or changes in existing flow requirements.

The staff evaluated the information and concluded that the specified tube thermal resistance value is appropriate for the water conditions, temperature, and flow. The heat exchanger monitoring program would remain adequate to ensure heat exchanger performance would satisfy design parameters at EPU conditions because the increased post-accident temperatures would not be present for sufficient time to significantly reduce heat exchanger performance.

Based on a review of the information that was submitted, the NRC staff found that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the ICW system to perform its safety functions. Because design limitations of affected SSCs will not be exceeded and licensing-basis considerations will continue to be satisfied, the staff agrees that the capabilities of the ICW system would remain adequate for the proposed power uprate. Furthermore, existing GL 89-13 programmatic controls will continue to assure that heat exchanger performance is maintained consistent with licensing-basis considerations following implementation of the proposed power uprate.

Conclusion

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

Reactor Auxiliary Cooling Water Systems (Component Cooling Water System)

Regulatory Evaluation

Reactor auxiliary cooling water systems circulate water to remove heat from plant components during plant operation, plant cooldown, and post accident conditions. The reactor auxiliary cooling water system for the PTN is the component cooling water (CCW) system. The CCW system is a safety-related system designed to supply cooling water to safety-related emergency core cooling system components and reactor auxiliaries. The system serves as an intermediate barrier between components containing reactor coolant and the SWS.

The NRC staff's review for proposed power uprates focuses on the continued capability of the CCW system to adequately cool critical plant equipment in accordance with licensing-basis assumptions. The acceptance criteria that are most applicable to the staff's review of the CCW system for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC-4, "Environmental and Dynamic Effects Design Bases," 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; GDC-5, "Sharing of Structures, Systems, and Components," insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and GDC 44, "Cooling Water," insofar as a

system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions should be provided.

The design criteria used during licensing of PTN predate those provided in 10 CFR Part 50, Appendix A. The PTN design criteria were developed based on the 1967 Atomic Energy Commission Proposed General Design Criteria. There is no specific PTN design criterion analogous to GDC-4 for the CCW system to be compatible with environmental conditions associated with normal operation and postulated accidents. Similarly, there is no specific PTN design criterion analogous to GDC-44 on cooling water that requires a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under normal operating and accident conditions. However, the design of the CCW system incorporates capabilities consistent with these design criteria.

The licensee addressed concerns regarding over-pressurization of isolated piping inside containment, and steam voiding and water hammer effects in piping inside containment for the CCW System following a loss-of-coolant accident with a loss of offsite power. In response to GL 96-06, "Assurance of Equipment Operability and Containment Integrity during Design Basis Accident Conditions," the licensee designed the CCW system to preclude the formation of steam voids under accident conditions. Specifically, the level in the CCW system head tank is such that temperatures of approximately 270 °F would not result in steam void formation.

The staff's review of the CCW system is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.3, "Auxiliary Coolant System," of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

NRC Technical Evaluation

The CCW system is designed to remove heat from plant components during plant operation, plant cooldown, and post accident conditions. Each CCW system consists of three pumps, three heat exchangers, one surge tank, one head tank, a chemical pot feeder, piping, valves, and controls. The CCW pumps circulate cooling water through parallel flow paths through various components, where the water picks up heat from other systems and transfers the heat to the ICW system via the CCW heat exchangers. The safety-related and nonsafety related components served by the CCW include the following:

- spent fuel pit heat exchangers
- residual heat removal heat exchangers
- normal containment coolers
- emergency containment coolers
- control rod drive mechanism coolers
- non-regenerative heat exchanger
- waste gas compressors
- sample heat exchangers
- reactor coolant pump thermal barriers
- excess letdown heat exchanger

- seal water return heat exchanger
- charging pump fluid drive
- bearing and/or seal coolers for reactor coolant and emergency core cooling system pumps

The licensee typically operates the CCW system with one CCW pump and two or three CCW heat exchangers in service to accommodate the heat removal loads during normal full power operation. The licensee described that two pumps and three heat exchangers would be used to remove the residual and sensible heat during unit shutdown. If the licensee does not place one of the pumps or one of the heat exchangers in service, safe shutdown of the unit is not affected; however, more time would be needed for cooldown.

The licensee's loss of coolant accident analysis modeled operation of one CCW pump and two CCW heat exchangers to accommodate the heat removal loads. The licensee described that the CCW system can be separated into redundant headers through operator closure of cross-connect valves. Closure of the valves allows isolation of a passive failure in the system while maintaining cooling water flow to the necessary engineered safeguards equipment.

Operation at EPU conditions would result in increased heat dissipation through the CCW system. The licensee proposed retaining existing system flow rates for accident scenarios and shutdown cooling; however, the licensee planned to increase flow rates for normal operations and refueling scenarios at EPU conditions due to modifications (i.e. replacement of normal containment coolers and installation of a supplemental SFP heat exchanger). The higher EPU heat loads would cause an increase in various CCW system piping temperatures, dependent upon the operating scenario.

The licensee's evaluation of the impact that EPU will have on the capability of the CCW system to provide essential cooling water to plant components during plant operation, plant cooldown, and post-accident conditions is provided in Section 2.5.4.3 of the PTN EPU Licensing Report. The licensee established the following acceptance criteria for evaluation of CCW system performance at EPU conditions:

- transfer the EPU design basis accident heat load to the ICW system using one CCW pump and two CCW heat exchangers at a maximum ICW temperature of 100 °F.

- transfer the EPU RHR Cooldown heat load to the ICW system while maintaining CCW supply temperature within the current design basis limit (≤125 °F).

- transfer the EPU heat loads of normal operations to the ICW system while maintaining CCW supply temperature within the current design basis limit (≤105 °F).

- transfer the EPU heat loads of refueling operations to the ICW system while maintaining the CCW supply temperature at or below the temperatures evaluated for current UFSAR cases (85 °F and 105 °F).

The licensee found that the CCW system heat load would not significantly change due to the increase in power associated with the EPU during normal plant operation. The replacement

normal containment coolers, the existing control rod drive mechanism coolers, and the letdown heat exchangers would have increased heat loads because of the small increase in reactor coolant system temperature for EPU operations, and the SFPCPS heat exchangers would have an increased heat load because of the increased decay heat. The remaining components served by the CCW system would be unchanged. The licensee calculated the increased heat load for normal and maximum letdown cases and determined the heat load would increase by less than 6 percent. The replacement of the normal containment coolers would also slightly increase CCW system flow. As noted in the ICW system review, the licensee also proposed a small decrease in the CCW heat exchanger resistance to improve margin. The licensee evaluated the overall effect of the change and determined that adequate flow for normal operating conditions would continue to be provided by a single CCW pump and the peak CCW temperature would remain within limits. The staff reviewed the considerations affecting the evaluation and concluded that the changes would be small enough to be accommodated by existing margin and the additional margin provided by the small decrease in heat exchanger resistance.

The reactor cooldown cases provide the greatest heat loads and are the limiting cases relative to CCW heat exchanger performance during normal plant shutdown conditions. The maximum CCW heat load during normal cooldown occurs when the RHR system is first placed in service, which could be as early as four hours after reactor shutdown. During cooldown the initial residual heat removal (RHR) flow is throttled to limit the reactor coolant system cooldown rate and the CCW heat exchanger outlet temperature. The licensee limits the maximum CCW outlet temperature of 125 °F, which results in a longer cooldown time at EPU conditions. However, the cooldown time would remain within the 36 hours included in the technical specifications. The staff concluded that existing controls to regulate the reactor coolant flow rate through the RHR heat exchangers would be sufficient to assure that CCW system design limitations would not be exceeded and the time to achieve cold shutdown would remain acceptable based on the small effect of the EPU on the overall heat transfer necessary for plant cooldown.

The licensee also evaluated the effect of the EPU on post-LOCA heat removal via the CCW heat exchangers during the recirculation phase of the accident. The licensee provided a summary of the containment heat removal analysis in Section 2.6.1 of the EPU Licensing Report. The analysis assumed a single CCW pump cooling a single RHR heat exchanger and transferring that heat load plus a minimal additional CCW system heat load to two single CCW heat exchanger. The analysis demonstrated that containment heat removal requirements through the CCW system were satisfied with respect to post-accident containment temperature and pressure. The staff's evaluation of containment heat removal for EPU conditions is provided in Section 2.6.1 of this safety evaluation.

The licensee evaluated the effect of the increase in containment heat loads imposed on the CCW System during accident conditions while maintaining current CCW heat exchanger tube resistance values and system flow rates. Under these conditions, the peak CCW system temperature was calculated to exceed the current analyzed limit of 150 °F and reach 158.6 °F for a period of a few hours after the limiting accident at EPU conditions. The licensee evaluated the effects of the increase in cooling water supply temperature on safeguard pumps that rely on the CCW system for cooling internal parts during accident conditions and determined the higher CCW supply temperature would not be detrimental to safeguard pump operation at EPU conditions. The NRC staff considered the evaluation and, based on the conservative

assumptions regarding conditions, concluded the pumps would not be affected by the brief calculated temperature increase above the existing analyzed limit.

The licensee evaluated the original responses to NRC GL 96-06 related to potential heatup and over-pressurization of CCW system piping and concluded the responses are not affected by EPU conditions since there are no physical changes or operational changes required by the EPU that would affect the containment penetration piping, isolation valves, or installed relief valves. The CCW system head tank would continue to provide sufficient static pressure to preclude steam void formation during the short time post-accident that CCW flow would be stopped. Therefore, the CCW system would remain adequately protected against the environmental conditions associated with postulated accidents.

The licensee provided information demonstrating adequate CCW system heat removal capability to maintain temperatures within design limits. Thus, evaluations of the RHR and CCW have demonstrated the capability of the CCW system to support normal and design basis accident/event cooling requirements at EPU conditions. Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the CCW system to perform its safety functions.

Conclusion

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

Ultimate Heat Sink

Regulatory Evaluation

The ultimate heat sink (UHS) provides the cooling medium for dissipating the heat removed from the reactor and its auxiliaries during normal operation, shutdown, refueling, and accident conditions. The UHS for PTN is the closed cooling water canal system serving the PTN site.

The NRC staff's review for proposed power uprates focuses on the continued capability of the UHS to adequately serve as a source of cooling water for critical plant equipment in accordance with licensing-basis assumptions. The acceptance criteria that are most applicable to the staff's review of the UHS for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC-5, "Sharing of Structures, Systems, and Components," insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and GDC 44, "Cooling Water," insofar as a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions should be provided.

The staff's review of the UHS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing

licensing-basis considerations as discussed primarily with respect to maximum ICW supply temperature in Section 9.3, “Auxiliary Coolant System,” of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

NRC Technical Evaluation

The UHS at PTN is a closed-loop cooling canal system. The closed-loop cooling water canal system is a shared heat sink that accepts the combined heat discharged to cooling water systems from the operation of Turkey Point fossil Units 1 & 2, and nuclear Units 3 & 4. The canal system accepts the heated water discharged from the condensers and other plant equipment at one end (discharge) and returns cooled water at the opposite (intake) end. The licensee described that the total volume of water in the cooling canals is approximately 12,300 acre-feet (4 billion gallons).

The ICW system draws cooling water from the intake end of the canal system at the intake structure for Units 3 and 4. The intake structure is Seismic Class I to the extent necessary to ensure that water is always available to the ICW system. As discussed in Section 2.5.4, Station Service Water System (or ICW at PTN), of this safety evaluation, the ICW system provides cooling water for heat removal from the safety-related CCW heat exchangers. The licensee determined that the existing minimum required ICW flow rate to the CCW heat exchangers of 15,200 gpm would remain acceptable for removal of postulated accident heat loads and condenser cooling water flow rates would remain unchanged at EPU operating conditions. Therefore, the effect of operation at EPU conditions on the UHS would be limited to a change in the necessary heat dissipation to maintain an acceptable UHS temperature.

The licensee determined the maximum increase in cooled water temperature leaving the cooling canal system to return to the units as a result of operation of two units at EPU conditions would be approximately 0.9 °F, from 91.9 °F to 92.8 °F. In the attachment to the FPL letter dated April 14, 2011, the licensee described the assumptions and methodology used to evaluate the effects of the EPU on the UHS. The licensee used a set of meteorological data for the 5-year period from January 1998 through December 2002 from the National Climatic Data Center for Miami International Airport. The model considered heat addition through radiation and operation of the four Turkey Point plants. Heat rejection was modeled for radiation, conduction to the atmosphere, and evaporation. The model used a constant surface area, but a variable water volume based on the canal system water elevation historically following the tide in Biscayne Bay.

The results of the UHS temperature change as a result of operation at EPU conditions remain well within the existing licensing bases of the Turkey Point units. Technical Specification 3.7.4 requires that the average supply water temperature to the UHS be less than or equal to 100 °F in operational modes 1 through 4. If the temperature is greater than 100 °F, the TSs require shutdown of both units.

The staff evaluated the information and concluded that the capacity of the PTN UHS would remain adequate to support operation at the EPU power level. Since the modeled heat rejection mechanisms are temperature dependent, the staff agrees with the FPL assessment that the temperature of the cooling canal system would only increase slightly as it approaches a new thermodynamic equilibrium with the environment.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the cooling canal system that serves as the PTN UHS. The staff has reasonable assurance that the UHS would remain capable of performing its licensing-basis functions following EPU implementation because a small increase in canal temperature would increase all modes of heat rejection to the environment and the plant has significant margin between the maximum experienced and expected canal temperatures and the temperature used in the safety analyses.

Auxiliary Feedwater System

Regulatory Evaluation

In conjunction with a Seismic Category I water source, the auxiliary feedwater (AFW) system functions as an emergency system for the removal of heat from the primary system when the main feedwater system is not available. The auxiliary feedwater system is also used to provide decay heat removal capability necessary for withstanding or coping with a station blackout.

The NRC staff's review for proposed power uprates focused on the system's continued ability to provide sufficient emergency feedwater flow at the expected conditions (e.g., steam generator pressure) to ensure adequate cooling with the increased decay heat. The staff 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 acceptance criteria that are most applicable to the staff's review of the CCW system for proposed power uprates are based on 10 CFR Part 50, Appendix A, GDC-4, "Environmental and Dynamic Effects Design Bases," 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; GDC-5, "Sharing of Structures, Systems, and Components," insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; GDC-34, "Residual Heat Removal," insofar as it requires that a residual heat removal (RHR) system be provided to transfer fission product decay heat and other residual heat from the reactor core; and GDC 44, "Cooling Water," insofar as a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions should be provided.

The design criteria used during licensing of PTN predate those provided in 10 CFR Part 50, Appendix A. The PTN design criteria were developed based on the 1967 Atomic Energy Commission Proposed General Design Criteria. There is no specific PTN design criterion analogous to GDC-4 for the AFW system to be compatible with environmental conditions associated with normal operation and postulated accidents. Similarly, there are no specific PTN design criteria analogous to GDC-34 on residual heat removal and GDC 44 on cooling water that require a system with the capability to transfer fission product decay heat and other residual heat from the reactor core and to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions. However, the design of the AFW system incorporates capabilities consistent with these design criteria.

The staff's review of the AFW system is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 9.11, "Auxiliary Feedwater System," of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

NRC Technical Evaluation

The AFW system consists of three four stage turbine-driven pumps shared between the two units. The three AFW pumps discharge through check valves to one of two redundant discharge headers. The licensee normally aligns the system valves such that Pump A discharges to the Train 1 auxiliary feedwater header and Pumps B and C normally discharge to the Train 2 auxiliary feedwater header. Each train can supply feedwater to each steam generator through a flow control valve (FCV), flow transmitters, and isolation valves. After passing through the FCV, each line taps into the feedwater line for the associated steam generator downstream of the main feedwater control valves.

The normal source of water for the AFW system is two condensate storage tanks (CSTs), each with a nominal capacity of 250,000 gallons. A secondary nonsafety source of water can be provided from the 500,000-gallon demineralized water storage tank (DWST). There are two standby steam generator feed pumps (SSGFPs) - one diesel and one electric - that meet the design requirements of flow and pressure during startup, shutdown, and hot standby. These pumps backup the AFW system in the event that the AFW system does not function properly, however these pumps are not designed to the safety class requirements applicable to the AFW system and are not required to satisfy design basis requirements. The DWST supplies water to the SSGFPs.

Implementation of the EPU would increase AFW system flow required to mitigate the various design basis events. The licensee determined that the limiting event in terms of total flow from a single pump would be a dual-unit loss of offsite power event, assuming one AFW pump is out-of-service and failure of an additional pump. In this case, the licensee determined the required minimum flow from the single remaining pump would increase from a total flow of 466.8 gpm to a total flow of 624.8 gpm, or approximately 312.4 gpm per unit. The licensee determined that the limiting event in terms of total flow to a single unit would be the loss of normal feedwater event with failure of a single piping header. In this case, the required minimum flow would increase from 310 gpm to 373 gpm through a single header to one unit.

The licensee determined the existing AFW system would supply the required flow with minor changes to the AFW system pumps and the FCVs supplying each steam generator. By letter dated August 11, 2011,[65] the licensee confirmed that the changes to the pumps involve only refurbishment of the pump, which limits modifications to like-for-like replacement. The proposed changes to the FCVs involve removal of the FCV limit stops, which does not change the design and function of the valves. The licensee determined that these changes would allow the pumps to deliver the required minimum flow to each steam generator for the loss of normal feedwater event. This capability would be subject to verification by inservice testing. Since the proposed

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changes to the design and operation of the AFW system would be limited in scope such that the design and operation of the system components would remain within existing bounds for design and operation, the AFW system would be acceptable for operation at EPU.

The licensee described that the SSGFPs are intended to back up the AFW pumps. As described in Section 2.5.1.4 of the EPU Licensing Report, the required flow from the SSGFPs at EPU conditions would remain well within the design capacity of the pumps, and, therefore, the SSGFPs are acceptable for operation at EPU conditions.

The implementation of the EPU would also change the required inventory of water stored in the CSTs. The current licensing basis inventory was based on maintaining the plant at hot standby for 15 hours followed by a 4-hour cooldown to RHR entry conditions. The licensee elected to change the licensing basis for the CST inventory to that specified in Branch Technical Position (BTP) 5-4 of NUREG-0800, “Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants.” The guidelines of BTP 5-4 specify that the CST inventory be sufficient to operate for four hours at hot standby and then provide for cool down to RHR entry conditions. In conformance with FPL's response to GL 81-21, “Natural Circulation Cooldown,” the licensee would also limit the natural circulation cool down rate to 25 °F per hour with 50 °F subcooling as part of the EPU licensing basis. The licensee determined that the licensing basis change to conform to the guidelines of BTP 5-4 and the licensee’s response to GL 81-21 would reduce the minimum usable inventory required from 199,100 gallons to 195,331 gallons. The licensee determined this volume would also be sufficient to maintain the plant at hot standby for 18 hours and exceeds the required SBO inventory. The decrease in minimal usable inventory to 195,331 gallons results in the minimum indicated volume also decreasing. The licensee did not propose a change to the TS 3.7.1.3 required minimum CST volume of 210,000 gallons. Therefore, the TS value remains bounding and acceptable.

The staff reviewed the change in licensing basis for determining the necessary minimum CST inventory. The staff found that the change would provide substantial additional margin because the time at hot standby would be significantly decreased. However, the proposed time at hot standby is consistent with the staff regulatory position presented in BTP 5-4. Therefore, the staff has reasonable assurance an adequate inventory of CST water would be available for operation at EPU.

The implementation of the EPU would also increase the required inventory in the DWST to support operation of the SSGFPs. The current licensing basis for the SSGFPs is to provide feedwater necessary to maintain a single reactor plant in hot standby for 6 hours or both reactor plants in hot standby for 2 hours, based on allowing sufficient time to restore the AFW system or provide additional water to the DWST. The licensee calculated an increase in the required volume of water from 65,000 gallons to 77,000 gallons. This is greater than an 18 percent increase in volume to support the 15 percent power increase associated with the EPU. Considering essentially unchanged allowances for level indication instrument uncertainty and unusable volume, the licensee determined an increase in the minimum indicated volume from 135,000 gallons to 145,000 gallons would ensure availability of the required volume with margin. The licensee proposed to increase the minimum indicated DWST inventory included in TS 3.7.1.6 to the 145,000 gallon value. The proposed minimum indicated volume retains adequate margin consistent with the PTN licensing basis, and, therefore, the proposed TS change is acceptable.

The staff evaluated the remainder of the bases for acceptance of the AFW system for operation at the EPU power level. The staff evaluated the protection of essential portions of the AFW systems from changes in dynamic effects associated with equipment failures at the EPU power level in Sections 2.2.1 and 2.5.3 of this safety evaluation. The staff evaluated the capability to operate necessary portions of the AFW system from outside the control room in Sections 2.10 and 2.11 of this safety evaluation. The adequacy of the AFW system to provide adequate decay heat removal and reactor core cooling to mitigate design basis accidents at the EPU power level with the design full flow capacity is evaluated in Section 2.8.5 of this safety evaluation. The ability of the CST and the AFW system to supply sufficient feedwater to remove decay heat from both units during station blackout conditions is evaluated in Section 2.3.5 of this safety evaluation. Based on the referenced evaluations of AFW system capability, the staff determined that the AFW system satisfies applicable acceptance criteria for operation at the EPU power level.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the AFW system that serves both units at PTN. The staff has reasonable assurance that the AFW system would remain capable of performing its licensing-basis functions following EPU implementation because the design operation of the AFW pumps would remain within existing bounds and the inventory remains adequate to support natural circulation cooldown to RHR entry conditions.

2.5.5 Balance-of-Plant Systems

Main Steam

Regulatory Evaluation

The main steam system transports steam from the steam generators to the power conversion system and various auxiliary steam loads. The portions of the main steam system from the steam generators up to and including the main steam isolation valves, the atmospheric relief valves, and the main steam safety valves are designed as safety related. The main steam supply to the auxiliary feedwater pump turbine and turbine exhaust piping is also safety-related. The main steam system also provides a flow path for steam from the steam generators to the steam dump system.

The NRC staff's review of the main steam system for proposed power uprates evaluates system design limitations to assure that reactor safety will be preserved. Much of the NRC staff's review of the main steam system for proposed power uprates involves other areas of review that are evaluated in other sections of this SE. The effects of increased steam flow and changes in steam quality on erosion/corrosion are evaluated in Section 2.1; the capability of the main steam system to withstand the steam hammer loads that result from the rapid closure of the main steam isolation valves (MSIVs), the capability of the MSIVs to isolate steam flow within the time period required, design considerations associated with the rapid closure of the MSIVs, protection of the steam generators from overpressure conditions, and evaluations of piping stresses are addressed in Section 2.2; the transient effects on reactor performance of

postulated events involving the main steam system are addressed in Section 2.8; and protection of SSCs important to safety from the effects of high energy line breaks and missiles is evaluated in Section 2.5.1.

This section of the safety evaluation focuses primarily on the capability of the main steam system to provide a means to remove decay heat from the reactor. The acceptance criteria that are most applicable to the staff's review of the main steam system for proposed power uprates are based on GDC 34, insofar as the capability to transfer fission product decay heat and other residual heat from the reactor core at an acceptable rate should be provided.

The design criteria used during licensing of PTN predate those provided in 10 CFR Part 50, Appendix A. The PTN design criteria were developed based on the 1967 Atomic Energy Commission Proposed General Design Criteria. There is no specific PTN design criterion analogous to GDC-34 on residual heat removal that requires a system with the capability to transfer fission product decay heat and other residual heat from the reactor core. However, the design of the AFW system incorporates capabilities consistent with these design criteria.

The staff's review of the main steam system is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 10, "Steam and Power Conversion System," of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

<u>NRC Technical Evaluation</u>

The licensee's evaluation of the impact that the EPU will have on the capability of the main steam system to remove residual heat from the reactor core under normal and accident conditions is provided in Section 2.5.5.1 of the PTN EPU Licensing Report. Acceptable performance of the main steam system is based on maintaining the capability to cool the reactor to residual heat removal system entry conditions following operations at full EPU power.

The licensee described that the main steam system design pressure and temperature bound the maximum EPU operating conditions, and projected EPU full power operating conditions of approximately 803 psia and 519 °F at the outlet of the steam generator are bounded by the current licensed thermal power operating conditions. The no load conditions are not affected by the EPU because the reactor coolant system no load temperature would be unchanged. Therefore, the design conditions would remain bounding for EPU operation. However, the licensee determined that certain sections of reheat piping would be exposed to higher than current design pressures because the full flow pressure drop through the replacement high pressure turbine would decrease. The licensee determined that these nonsafety sections of piping could be rerated to encompass the higher operating pressures. Therefore, the design of the main steam piping would be acceptable for operation at EPU power levels.

The main steam safety valves (MSSVs) provide a means to remove heat through the main steam system at a rate sufficient to prevent over-pressurization of the steam generators for a variety of transient conditions. Each PTN unit has 4 MSSVs per steam generator. In Section 2.8.4.2, "Overpressure Protection during Power Operation," and Section 2.8.5, "Accident and Transient Analyses," of the EPU Licensing Report, the licensee presented its

evaluations confirming that the installed safety valve capacity would be adequate for overpressure protection. The NRC staff evaluation of this transient analysis is provided in Section 2.8.4 of this safety evaluation. The EPU analysis for loss of load included a change in the safety valve setpoints for each steam generator from 1085 psig, 1100 psig, 1115 psig, and 1130 psig to EPU values of 1085 psig, 1100 psig, 1105 psig, and 1105 psig. The proposed changes to Technical Specification Table 3.7.1-1 include these changes to the MSSV setpoints. Based on the staff's acceptance of the overpressure protection analyses and the transfer of the MSSV setpoint values to the proposed TSs, the staff found that the heat removal capacity of the MSSVs would be adequate for operation at EPU conditions.

The main steam system provides a path to remove decay heat through the main steam atmospheric dump valves (ADVs) and the steam dump system. The primary function of the ADVs is to provide a means for decay heat removal and plant cool down by discharging steam to the atmosphere when the condenser is not available. Under such circumstances, the ADVs in conjunction with the auxiliary feedwater system permit the plant to be cooled down from the pressure setpoint of the lowest-set main steam safety valves to the point where the residual heat removal system can be placed in service. In the event of a steam generator tube rupture in conjunction with a loss of offsite power, the ADVs would be used to cool down the reactor coolant system to a temperature that supports equalization of primary and secondary system pressures. The staff evaluated the capacity of the ADVs to support reactor cooldown to residual heat removal system operating conditions in Section 2.8.4 of this safety evaluation and to support pressure equalization following a steam generator tube rupture in Section 2.8.5 of this safety evaluation. The condenser steam dump system is discussed in Section 2.5.5, "Turbine Bypass."

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the main steam system to remove adequate decay heat. The NRC evaluations of system heat removal capacity have found that the main steam system will remain capable of performing its licensing-basis residual heat removal safety functions following EPU implementation. Therefore, the proposed EPU is acceptable with respect to the main steam system.

Main Condenser

The main condenser is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system (TBS). The NRC staff's review of the main condenser for proposed power uprates focuses primarily on the impact that an EPU will have on the control of radiological releases to the environment. For pressurized-water reactors, the effect of the proposed EPU on the concentration of radionuclides in the condenser is negligible because leakage from the reactor coolant system through the steam generator 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.

Turbine Bypass

The turbine bypass system (TBS) at PTN is known as the condenser steam dump system, and it is a nonsafety-related system designed to discharge a stated percentage of rated main steam flow directly to the main condenser, bypassing the turbine and enabling the plant to take step load reductions up to the capacity of the TBS without causing the reactor or turbine to trip. The Westinghouse original sizing criterion conservatively recommended that the steam dump system (valves and pipe) be capable of discharging 40 percent of the rated steam flow at full-load steam pressure to permit the nuclear steam supply system (NSSS) to withstand an external load reduction of up to 50 percent of plant-rated electrical load without a reactor/turbine trip. To prevent a trip, this transient requires all NSSS control systems to be in automatic, including the rod control system, which accommodates 10 percent of the load reduction. The steam dump system minimizes the potential for main steam safety valve (MSSV) lifting following a reactor trip from full power.

Each PTN unit is equipped with 4 condenser steam dump valves. The licensee determined that the valve capacity provides a total steam dump system capacity adequate for a ramp load reduction of 50 percent over 15 seconds from the EPU power level, but it would not be adequate for the instantaneous 50 percent step load reduction that was considered for operation at the CLTP. The licensee determined that the valve capacity would remain adequate to prevent exceeding MSSV setpoints following a reactor trip from full EPU power. This capacity also exceeds that necessary for prompt cooldown to residual heat removal system operation entry conditions. Because changes are not being made in the design and operation of the TBS and the system remains adequate for its residual heat removal function, a detailed evaluation of the TBS is not necessary.

Condensate and Feedwater

Regulatory Evaluation

The condensate and feedwater system (CFS) provides feedwater at the appropriate temperature, pressure, and flow rate to the SGs. The only part of the CFS that is classified as safety-related is the feedwater piping from the SGs up to and including the outermost containment isolation valves. The NRC staff's review of the CFS for proposed power uprates focused primarily on the effects of the proposed EPU on the capability to isolate portions of the system to support essential safety functions and to supply adequate feedwater during plant operation and shutdown. The effects of increased CFS flow on erosion/corrosion rates are evaluated in Section 2.1 of this SE; the capability of the main feedwater isolation valves (MFIVs) to isolate feedwater flow within the time period required, and the capability of CFS piping and supports to withstand postulated transient loads (such as those that result due to check valve slam) are evaluated in Section 2.2 of this SE; positive reactivity considerations and the transient effects of the CFS on reactor performance and the need for transient testing in this regard are addressed in Sections 2.8 and 2.12 of this SE; and, the consequences of component missiles and pipe breaks are evaluated in Sections 2.5.1.2 and 2.5.1.3 of this SE.

The acceptance criteria that are most applicable to the staff's review of the CFS for proposed power uprates are based on the following design criteria of 10 CFR Part 50, Appendix A:

GDC 4, “Environmental and Dynamic Effects Design Bases,” insofar as the system is appropriately protected against dynamic effects associated with possible fluid flow instabilities (e.g., water hammers) during normal plant operation as well as during upset or accident conditions; and GDC 44, “Cooling Water,” insofar as a system should be provided with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions and the capability to isolate components, subsystems, or piping if required so that the system safety function could be achieved assuming a single failure. The staff also considered existing plant licensing-basis considerations, especially with respect to maintaining CFS reliability and minimizing challenges to reactor safety systems during EPU operation.

The design criteria used during licensing of PTN predate those provided in 10 CFR Part 50, Appendix A. The PTN design criteria were developed based on the 1967 Atomic Energy Commission Proposed General Design Criteria. There is no specific PTN design criterion analogous to GDC-4 for the CFS to be compatible with environmental conditions associated with normal operation and postulated accidents. Similarly, there is no specific PTN design criterion analogous to GDC-44 on cooling water that requires a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under normal operating and accident conditions. However, the design of the CFS incorporates capabilities consistent with these design criteria.

Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 10, “Steam and Power Conversion System,” of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

NRC Technical Evaluation

The CFS was designed to transport condensed steam from the condenser to the steam generators at the most efficient temperature and pressure. For each unit, the system consists of three condensate pumps, two heater drain pumps, and two feedwater pumps. In addition, the system includes a gland steam condenser, steam jet air ejector condenser, two strings of five low pressure feedwater heaters, two strings of single high pressure feedwater heaters, main feedwater regulating valves, and feedwater isolation valves. Operation at EPU conditions would affect all major CFS components as a result of substantially higher feedwater flow rates and moderate changes in fluid pressures and temperatures throughout the system.

The licensee has identified modifications to the design and operation of the CFS to support EPU operation. Physical design modifications include replacement of the 3 condensate pumps, replacement of the high-pressure feedwater heaters, addition of an automatic turbine runback to minimize operator burden in the event of a condensate or heater drain pump trip, modification of the flow characteristics of the motor-driven main feedwater pumps, addition of a staggered time delay to the main feedwater pump suction pressure trip setpoints to minimize the likelihood of both pumps tripping simultaneously, modification of existing feedwater isolation valves (MFIVs) to perform the automatic backup feedwater isolation function, and modification of the main feedwater control valves (MFCVs) to provide increased feedwater flow capacity. The principle operational change would be the operation of 3 of 3 condensate pumps at EPU conditions instead of the current 2 of 3 pumps,

Feedwater Isolation

Consistent with the current licensing basis, the licensee proposed maintaining the feedwater pump discharge MOVs as the primary means of feedwater isolation. Following the modification of the MFIVs and associated bypass valves to provide automatic isolation, the licensee proposed to credit the MFIVs as the backup means of isolating main feedwater flow to a faulted steam generator. In combination with the main feedwater pump trip, these valves would replace the main feedwater pump discharge valve closure currently credited with the backup isolation function. The licensee described that the MFIVs would be designed to close in less than 30 seconds, which is comparable to the current closure time specified for the feedwater pump discharge valves. Closure times for the modified MFCVs are specified to be less than the closure times assumed in the EPU safety analysis described in Section 2.6.3.2, “Mass and Energy Release Analysis for Secondary System Pipe Ruptures,” of the EPU Licensing Report. Post-modification testing will be performed to verify the closure time.

Technical Specifications

The licensee proposed new TS 3.7.1.7, “Feedwater Isolation,” which would specify that the MFCVs, the MFIVs, and associated bypass valves be operable in operating modes 1, 2, and 3. Six MFCVs and six MFIVs are required to be operable and is consistent with Turkey Point’s design, one for each feedwater line and one for each bypass line. The content of proposed TS 3.7.1.7 would be consistent with the improved standard technical specification listed in NUREG 1431, “Standard TSs – Westinghouse Plants,” Revision 3.1. Specifically, for conditions involving one or more inoperable valves in different flow paths, the proposed actions would allow a 72-hour period to restore operability or close the inoperable valve. Also, for conditions involving two inoperable valves in the same flow path, the proposed actions would allow an 8 hour period to restore operability or close the inoperable valve. Finally, the proposed surveillance requirements include verification that all the valves actuate to the isolation position on an actuation signal on an 18-month interval and that valve closure time is within specified limits in accordance with the inservice test program. Therefore, the staff found the proposed TS 3.7.1.7 acceptable for EPU operation.

The staff found that the proposed quality and testing applied to the MFCVs and MFIVs would be consistent with the existing PTN licensing basis because the primary means of feedwater isolation would be provided by safety-related components, essential functions of the backup feedwater isolation capability would be provided by safety-related components, and the isolation valves would be subject to TS operability and testing requirements that assure a high reliability. Therefore, the staff found the proposed design of the feedwater isolation capability acceptable.

Heat Removal Capability

The licensee described its evaluation of the impact that the EPU will have on the CFS’s ability to provide feedwater to the SGs in Section 2.5.5.4 of the PTN EPU Licensing Report. During EPU operation, feedwater and condensate flow will increase and the increased flow will result in an increase in the system pressure drop. The licensee developed a model of the CFS for the planned EPU configuration and determined that the CFS will have sufficient margin to satisfy flow requirements for the uprated plant under normal operating and design transient conditions.

Based on the licensee's evaluation, the proposed system modifications, and existing operating experience, the staff concluded that the proposed CFS design would provide an adequate feedwater supply for EPU operation under normal operating and a reasonable spectrum of transient conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the CFS and finds that the staff has reasonable assurance that the CFS will remain capable of providing feedwater to the SGs under normal operating and certain transient conditions. The licensee has proposed appropriate modifications and TSs to maintain system isolation capability consistent with the plant accident analyses. Therefore, the CFS will continue to satisfy licensing-basis considerations and the proposed EPU is considered to be acceptable with respect to the CFS.

2.5.6 Waste Management Systems

Gaseous Waste Management Systems

Regulatory Evaluation

Gaseous waste management systems (GWMS) involve the gaseous radwaste system, which deals with the management of radioactive gases collected in the offgas system or the waste gas storage and decay tanks. In addition, it involves the management of effluents from the condenser air removal system, the SG blowdown flash tank, the containment purge exhaust, and building ventilation system exhausts. The NRC staff's review of the GWMS focuses on the effects that the proposed EPU may have on methods of treatment; expected releases; principal parameters used in calculating releases of radioactive materials in gaseous effluents; and the accumulation and management of explosive mixtures. The acceptance criteria for the GWMS that are most applicable to the staff's review of proposed power uprates are based on (1) 10 CFR 20.1302, insofar as it places specific limitations on the annual average concentrations of radioactive materials released at the boundary of the unrestricted area; (2) 10 CFR Part 50, Appendix A, GDC 60, "Control of Releases of Radioactive Materials," insofar as it specifies that the plant design include means to control the release of radioactive effluents; (3) 10 CFR Part 50, Appendix A, GDC 61, "Fuel Storage and Handling and Radioactivity Control," insofar as it specifies that systems that contain radioactivity be designed with suitable shielding and filtration; (4) 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for meeting the "as low as is reasonably achievable" criterion; and (5) 10 CFR Part 50, Appendix A, GDC 3, "Fire Protection," insofar as it specifies that systems and components important to safety be designed and located to minimize the probability and effects of explosions. Although GDC 60 and GDC 61 do not directly apply to PTN, the plant was licensed to similar plant-specific design criteria (i.e., PTN GDC 70 and PTN GDC 69, respectively). The staff's review of the GWMS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 11.1, "Waste Disposal System," of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

NRC Technical Evaluation

The GWMS at TPN collects, processes, and disposes of waste gases from various tanks and sampling systems plant-wide and provides hydrogen/nitrogen blanket gas supply and recycling services. The licensee described that most of the gas received by the system during normal operation is due to the blanket gases being displaced from the chemical and volume control system holdup tanks as they fill with liquid. Other sources include sampling operations and gas analysis for hydrogen and oxygen in the blanket gases. The system includes features to preclude buildup of explosive gas mixtures, predominantly through the control of oxygen. These gases are collected, compressed, and retained for decay. The licensee then either reuses the gases or discharges the gases to the environment through a monitored vent.

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 PTN 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 gaseous waste management systems, 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 safety evaluation, respectively.

Section 11.1.1 of the PTN UFSAR describes that the oxygen content in the GWMS is continuously monitored to prevent development of a potentially explosive gas mixture. The monitoring is performed in accordance with TS Surveillance Requirement 4.7.8, "Explosive Gas Mixture," and TS 3.7.8 specifies required actions if a hazardous mixture of gases develops. The licensee has measures in place 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 NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the GWMS to perform its functions. Because the increase in 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 of the effects of the proposed EPU on the capability of the GWMS to perform its functions and finds that the GWMS will continue to control the release of radioactive materials and preclude the possibility of waste gas explosions in accordance with the plant licensing basis. Therefore, the NRC staff concludes that the GWMS will continue to satisfy applicable criteria from the PTN licensing basis and the proposed EPU would be acceptable with respect to the GWMS.

Liquid Waste Management Systems

Regulatory Evaluation

The NRC staff's review of the liquid waste management system (LWMS) focuses on the effects that the proposed EPU may have on previous analyses and considerations related to the processing and management of liquid radioactive waste; methods of treatment; expected releases; and principal parameters used in calculating the release of radioactive materials in liquid effluents. The acceptance criteria for the LWMS that are most applicable to the staff's review of proposed power uprates are based on (1) 10 CFR 20.1302, insofar as it places specific limitations on the annual average concentrations of radioactive materials released at the boundary of the unrestricted area; (2) 10 CFR Part 50, Appendix A, GDC 60, insofar as it specifies that the plant design include means to control the release of radioactive effluents; (3) 10 CFR Part 50, Appendix A, GDC 61, insofar as it specifies that systems that contain radioactivity be designed with suitable confinement, shielding, and filtration; and (4) 10 CFR Part 50, Appendix I, Sections II.A and II.D, which set numerical guides for meeting the "as low as is reasonably achievable" criterion. Although GDC 60 and GDC 61 do not directly apply to PTN, the plant was licensed to similar plant-specific design criteria (i.e., PTN GDC 70 and PTN GDC 69, respectively). The staff's review of the LWMS is performed in accordance with the guidance provided in Section 2.1 of RS-001, Matrix 5. Acceptability is judged based upon conformance with existing licensing-basis considerations as discussed primarily in Section 11.1 of the PTN UFSAR, except where proposed changes are found to be acceptable based upon the specified review criteria.

NRC Technical Evaluation

The PTN LWMS is shared between the two units with the exception of the portions associated with collection inside containment, such as reactor coolant drains, containment floor drains, and containment sumps. The LWMS consists of process equipment and instrumentation necessary to collect, process, monitor and recycle/dispose of liquid radioactive waste. Section 11.1 of the PTN UFSAR describes radioactive fluids entering the waste disposal system are collected in tanks, processed as required, and then released under controlled conditions.

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 PTN 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 safety evaluation.
Based on a review of the information that was submitted, the NRC staff is satisfied that the licensee has adequately evaluated and addressed the impact of the proposed power uprate on the capability of the LWMS to perform its functions. Because the increase in offsite dose will be relatively small and the doses will remain a small fraction of the allowable Appendix I doses, the staff agrees that the capabilities of the LWMS will continue to satisfy the plant licensing basis following implementation of the proposed power uprate.

Conclusion

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

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 Section 2.5.6 of this SE, a separate evaluation of solid waste management systems is not required.

2.5.7 Additional Considerations

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

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions (e.g., diesel engine-driven generator sets). The NRC staff's review focuses on increases in emergency diesel generator (EDG) electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function. The licensee determined that the required quantities of available fuel will not change because operation at EPU conditions would not change the design fuel oil consumption rates. Therefore, the existing Technical Specification required fuel oil inventories remain adequate to support EDG operation at EPU load conditions. Accordingly, this area of review is not affected by the proposed power uprate and an evaluation of the fuel oil storage system is not required.

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 spent fuel pool 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 containment encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. The containment structure must be capable of withstanding, without loss of function, the pressure and temperature conditions resulting from postulated loss-of-coolant accidents (LOCAs), and secondary line breaks. The containment structure must continue to serve as a low leakage barrier against the release of fission products for as long as the postulated accident requires.

The Nuclear Regulatory Commission (NRC) staff's review covers the pressure and temperature conditions in the containment due to a spectrum of postulated LOCAs and secondary line breaks. The NRC's acceptance criteria for primary containment functional design are based on the following general design criteria (GDC) from Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants": (1) GDC 16 for the containment to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment; (2) GDC 50 for the containment and its associated systems being able to accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA; (3) GDC 38 for the containment heat removal system(s) function to rapidly reduce the containment pressure and temperature following any LOCA and maintain them at acceptably low levels; (4) GDC 13 for instrumentation to monitor variables and systems over their anticipated ranges for normal operation and for accident conditions; and (5) GDC-64 for monitoring reactor containment atmosphere for radioactivity that may be released from normal operations and postulated accidents. Specific review criteria are contained in NRC's NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (Standard Review Plan or SRP), Section 6.2.1.1.C.

NRC Technical Evaluation

The Turkey Point Nuclear Plant (PTN) containment is described in Section 5.1.2 of the Updated Final Safety Analysis Report (UFSAR) as:

> A post-tensioned reinforced concrete cylinder and a shallow dome, connected to and supported by a massive reinforced concrete foundation slab. The inside

surface of the structure is lined with a ¼” thick welded steel plate to insure a high degree of leak tightness.

The PTN containment design pressure is 55 pounds per square inch gauge (psig) and the design temperature is 283 °F.

A LOCA is mitigated with the PTN emergency core cooling system (ECCS) and the containment heat removal system. The ECCS consists of the passive accumulators, high head safety injection pumps, and the residual heat removal (RHR) pumps which also act as low head safety injection pumps. During the injection phase, the ECCS pumps take suction from the refueling water storage tank (RWST). During the recirculation phase, the residual heat removal pumps take suction from the containment sump. If high head injection is needed during the recirculation phase, the high head injection pumps take suction from the discharge of the residual heat removal pumps. Heat is rejected from the RHR system to the component cooling water (CCW) system through the RHR heat exchangers, and from the CCW system to the service water system through the CCW heat exchangers.

Heat removal from the containment atmosphere during a postulated accident is accomplished by the emergency containment cooling (ECC) system and the containment spray system. The ECC system consists of three containment fan cooling units. The containment spray system consists of two redundant pumps and two spray spargers. During the injection phase of a LOCA, the spray pumps take suction from the RWST. During the recirculation phase of the LOCA, the containment spray pumps, if needed, would take suction from the residual heat removal pumps.

Loss-of-Coolant Accident

The licensee evaluated the design-basis LOCA relative to the containment peak pressure and temperature response at EPU conditions. The containment analysis consists of two parts. First, the mass and energy release from a high energy line break is calculated. The mass and energy (M&E) release resulting from a LOCA are discussed in Section 2.6.3 of this safety evaluation report (SER) input. The second part of the containment analysis consists of calculating the pressure and temperature conditions within the containment resulting from this release of mass and energy into the containment by making use of NAI 8907, Rev. 16, “GOTHIC [Generation of Thermal Hydraulic Information for Containments] Containment Analysis Package Technical Manual,” Version 7.2a (QA), January 2006, computer code. GOTHIC is a general purpose computer program for the prediction of the thermal hydraulic conditions in nuclear power plant containments. GOTHIC solves the conservation equations for mass, momentum and energy for multi-component, multi-phase flow.

GOTHIC is developed for the Electric Power Research Institute (EPRI) by Numerical Applications, Incorporated. GOTHIC undergoes an extensive verification and benchmarking process against both analytic solutions and special effects and integral heat transfer and containment data. It is subject to 10 CFR Part 50, Appendix B and 10 CFR Part 21 requirements.

Section 2.6.1.2, “Technical Evaluation,” of Attachment 4 to the LAR, subsection 2.6.1.2.1 states that the GOTHIC containment modeling for PTN is consistent with the recent NRC-approved

R.E. Ginna Nuclear Power Plant (Ginna) evaluation model.[66] The Ginna analyses used GOTHIC 7.2. The PTN analyses use GOTHIC 7.2a. GOTHIC 7.2a is consistent with the NRC staff's conditions of acceptance placed on the use of GOTHIC in the Ginna SER. GOTHIC 7.2a also contains user-controlled enhancements. The licensee stated that none of these enhancements were used for the PTN calculations. The differences in the GOTHIC code versions are documented in Appendix A of the GOTHIC User Manual Release Notes.[67] Since the licensee followed the staff's guidance on the use of GOTHIC, the staff finds the licensee's use of GOTHIC for LOCA and main steamline break accident analyses to be acceptable.

The LOCA M&E release analysis and associated containment integrity analysis were revised from the original EPU submittal, October 21, 2010, to address the EPITOME code issue, as discussed in Section 2.6.3 of this SE. In addition to reanalyzing the LOCA containment analysis to correct the EPITOME error, the licensee discovered that the values assumed in the PTN EPU analysis for the containment volume, the initial containment temperature, and the hot leg recirculation injection flows required revision. Specifically, the analysis value for the containment free volume was changed from the previous value of 1.55E6 ft^3, to a range of values (1.45E6 ft^3 to 1.60E6 ft^3); the analysis value for the initial containment temperature increased from 126 °F to 130 °F; and the hot leg recirculation flow to the RCS supporting the LOCA long-term equipment qualification (EQ) case was modified as a result of a hydraulic calculation correction.

Along with the EPITOME error having adverse effects on the LOCA M&E during the reflood phase, the decreased analysis value for containment volume, the increased initial containment temperature, and hot leg recirculation flow change all have adverse effects on the calculated containment response. To accommodate these adverse effects, the licensee made additional changes to the LOCA analysis from the original EPU submittal, as well as to the main steamline break analysis when applicable. These changes include: the initial containment pressure value being reduced, as defined by the proposed technical specification (TS) change (see Section 2.6.7, Technical Specification Changes, of this SER); the relative humidity being increased; a revised decay heat model; the analysis value for the containment spray droplet size was reduced; modifications to the control scheme for the emergency containment coolers; and the containment flow rate.

The assumptions and initial conditions that were used as inputs for the revised LOCA analysis and associated containment integrity analysis are discussed below.

The licensee assumed initial containment conditions which result in conservative calculations. The initial pressure is assumed to be 1.4 psig. The initial relative humidity is 30 percent. These conditions result in more air mass in containment which produces a higher accident pressure. A relatively high initial air temperature results in a higher pressure (for the same air mass). The licensee assumes a minimum value for the free containment volume of 1.45E6 ft^3, which is conservative and is therefore acceptable.

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[66] ML061380103
[67] NAI 8907-02, Rev. 17, "GOTHIC Containment Analysis Package User Manual," Version 7.2a (QA), January 2006

The licensee models the heat sinks as GOTHIC thermal conductors. This increases thermal resistance. Conservatively low surface areas are used for the heat sinks. Gaps between insulation, steel and concrete also increase thermal resistance.

The licensee models the injection of nitrogen gas from the ECCS accumulators into the containment. This increases the containment accident pressure. The containment fan coolers are modeled in GOTHIC as a cooler/heater component with heat removal rate for one fan cooler defined by a function.

The licensee developed a sump recirculation model for the GOTHIC calculation which uses the residual heat removal (RHR) and component cooling water (CCW) heat exchangers and pumps, with intake cooling water as ultimate heat sink. Recirculation flow from the sump is modeled as a boundary condition. The GOTHIC heat exchanger model has been benchmarked against vendor specification sheets to ensure it adequately predicts active heat removal.
The licensee assumes two possible single failures: maximum and minimum safeguards safety injection flow. Both assume a loss of offsite power at the onset of the event which necessitates use of the emergency diesel generators. The minimum safeguards safety injection flow assumption is the loss of one train of safeguards equipment by the assumed single failure of an emergency diesel generator. This leaves available one containment spray pump in the injection phase, two emergency containment coolers (ECCs), one RHR pump and heat exchanger (with recirculation sprays), one CCW pump and two CCW heat exchangers, and one intake cooling water pump acting as the ultimate heat sink. The maximum safeguards safety injection flow case assumes full safety injection flow but a single failure of one train of containment spray. These single failure assumptions are typically assumed for Westinghouse-designed PWRs and the NRC staff has previously found these assumptions to be acceptably limiting since the minimum case minimizes core cooling and the maximum case results in faster core reflood which results in a faster release of heat to the containment as well as minimizing containment cooling by crediting only one train of containment spray.

In the case of either the minimum SI flow single failure or the maximum SI flow single failure, one train of containment spray is unavailable, however two ECCs are available. If one of the two normally actuated emergency containment coolers fails to start due to failure of one diesel generator, the third (swing) emergency containment cooler will be automatically loaded onto the energized bus.

The containment spray is credited during the injection phase and the recirculation phase of the LOCA. Containment spray initiates on a coincidence of two sets of two-out-of-three high-high containment pressure signals. The spray takes suction from the refueling water storage tank (RWST). The RWST water is assumed to be at 100°F. This is the maximum auxiliary building temperature listed in the PTN UFSAR and is, therefore, conservative and acceptable. The initial spray drop size is assumed to be 700 microns, which is defined by the plant-specific spray nozzle hardware and is, therefore, acceptable. GOTHIC models the heat and mass transfer to the drop as it falls through the containment atmosphere. Any un-evaporated spray water is added to the sump. Comparisons of the GOTHIC drop evaporation model with data show acceptable agreement.

The major heat exchangers used in the PTN containment analysis to model heat removal from the containment are the ECCs, the RHR heat exchangers and the CCW heat exchangers. The

PTN containment spray system does not contain heat exchangers. The CFC, RHR and CCW heat exchangers are modeled with GOTHIC heat exchanger components. The licensee states that the performance of these heat exchanger models was benchmarked against design conditions and low flow conditions from the heat exchanger specifications data. The staff finds this acceptable as this approach ensures that the models adequately predict heat removal.

The ECCS accumulators contain nitrogen as a cover gas over the water surface. Upon discharge of the accumulator water into the reactor, the nitrogen gas is assumed to be released to the containment where it contributes to the total containment pressure. The licensee models the nitrogen release as a GOTHIC flow boundary condition in the LOCA containment model only. The nitrogen release rate was conservatively calculated by maximizing the mass available to be injected. The nitrogen gas release rate was used as input for the GOTHIC function, as a specified rate over a fixed time period. The staff has reviewed the licensee's description of the model and finds it a reasonable representation of the physical process and therefore acceptable.

The licensee determined that the peak pressure as a result of a LOCA occurs due to a double-ended pump suction break. The calculated peak containment pressure is 53.9 psig. The containment design pressure is 55 psig. The licensee uses the containment design pressure for P_a (the pressure required by 10 CFR Part 50 Appendix J to be used for leakage rate testing of the containment and its penetrations). This is conservative and therefore acceptable.

The peak structural temperature of the containment as a result of a LOCA occurs for the double-ended pump suction break with minimum safeguards. The calculated value is 273.5 °F. The containment peak structural temperature acceptance limit is 283 °F.

The licensee's analyses show that the peak containment pressure at 24 hours following start of the LOCA is less than half the peak containment pressure. It is therefore acceptable, following the guidance of Standard Review Plan 6.2.1.1.C to assume that the containment leakage rate after 24 hours is less than half the technical specification containment leakage rate limit of L_a.

The licensee evaluated the containment response to the limiting LOCA under EPU conditions for licensee renewal and determined that it has no effect on license renewal system evaluation boundaries. Further, the analytical results of the containment response do not add any new or previously unevaluated aging effects that necessitate a change in aging management programs or require a new program that would affect the system boundaries for license renewal. Based on this information, the NRC staff concludes that the containment response to the limiting LOCA under the proposed EPU would not impact license renewal.

Main Steamline Break

The licensee performed analyses of the containment response to the main steamline break analysis relative to the containment peak pressure and temperature at EPU conditions. The containment response evaluates peak containment pressure and temperature against maximum design values.

The licensee assumes two possible single failures: mass and energy related secondary side failures and containment safeguards failure. Both assume offsite power is present (maximizing

heat transfer from the primary to secondary sides), system actuation delays consistent with offsite power available, one CCW pump, two CCW heat exchangers, and intake cooling water acts as the ultimate heat sink. The mass and energy related secondary side failure assumes a secondary side failure (i.e. auxiliary feedwater run-out protection failure, failure of the faulted loop feedwater isolation valve) that maximize mass and energy releases. This leaves available two CS pumps, two emergency containment coolers, and two intake cooling water pumps. The limiting containment safeguards failure is assumed to be the loss of one train of containment safeguards due to the failure of an emergency diesel generator sequencer. This case leaves available one CS pump, one emergency containment cooler, and one intake cooling water pump. These single failure assumptions are typically assumed for Westinghouse-designed PWRs and the NRC staff has previously found these assumptions to be acceptably limiting since the mass and energy related secondary side failures maximizes the M&E releases and the containment safeguards failure minimizes containment cooling by the loss of one train of containment safeguards.

The steamline break containment response was also analyzed with GOTHIC 7.2a, which has been qualified for calculating containment response as discussed earlier in this section under "Loss-of-Coolant Accident." The steamline break containment response was analyzed for each of the mass and energy releases from a spectrum of cases, as discussed in Section 2.6.3 of this safety evaluation report input. The analysis includes the effects of the EPU to 2660 megawatts thermal (MWt) which includes pump heat and measurement uncertainty, the addition of a backup isolation valve on the main feedwater bypass line, upgrades to the main feedwater isolation valve, and the addition of 50/5 lead/lag on the low steamline pressure signal.

The licensee determined that the limiting containment pressure case for the EPU is a 1.0 ft^2 split break initiated from hot zero power with a single failure of the main steamline check valve. The peak containment pressure was calculated to be 53.4 psig. The calculated peak pressure is below the containment design pressure of 55 psig, and therefore acceptable.

The peak structural temperature of the containment occurs for the same case. The calculated value is 279.2 °F. The containment peak structural temperature acceptance limit is 283 °F.

The licensee evaluated the containment response to the MSLB under EPU conditions and determined that it has no effect on license renewal system evaluation boundaries. Further, the analytical results of the containment response do not add any new or previously unevaluated aging effects that necessitate a change in aging management programs or require a new program that would affect the system boundaries for license renewal. Based on this information, the NRC staff concludes that the containment response to the MSLB under the proposed EPU would have no impact on license renewal.

Conclusion

The NRC staff has reviewed the licensee's assessment of the containment pressure and temperature transient during a DBA-LOCA and MSLB. Based on the evaluation provided under Section 2.6.3, the NRC staff concludes that the licensee has adequately accounted for the increase of mass and energy that would result from the proposed EPU. The NRC staff further concludes that containment systems will continue to provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained. The NRC staff also

concludes that the containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and will continue to meet the requirements of GDCs 13, 16, 38, 50, and 64 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to containment functional design.

2.6.2 Subcompartment Analysis

Regulatory Evaluation

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The NRC staff's review for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The NRC staff's review focused on the effects of the increase in mass and energy release into the containment due to operation at EPU conditions, and the resulting increase in pressurization. The NRC's acceptance criteria for subcompartment analyses are based on: (1) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects; and (2) GDC 50, insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments. Specific review criteria are contained in SRP Section 6.2.1.2.

NRC Technical Evaluation

The licensee classifies the subcompartment analyses as short-term LOCA analyses since the pressure pulse of interest for these analyses is generally less than 3 seconds. These short term LOCA analyses are performed for PTN for the reactor cavity and the three steam generator enclosures. Both double-ended and slot type reactor coolant breaks were postulated.

The NRC has approved the application of leak-before-break (LBB) methods at PTN[68] for the reactor cavity region. Further, application of LBB has reduced the break size for postulated breaks within the steam generator enclosures. Thus, the current analysis of record steam generator subcompartment analyses bound the LBB breaks.

The SATAN computer program, used in this analysis, was approved by the NRC in WCAP 8264-P-A.[69]

A break in a high energy line at EPU conditions results in a higher mass flux into the subcompartment because of the lower reactor coolant system temperature. This would

[68] Letter, G. E. Edison (NRC) to W. F. Conway (FPL), "NRC Generic Letter 84-04, Asymmetric LOCA Loads for Turkey Point Units 3 and 4," November 28, 1988
[69] WCAP-8264-P-A, Rev. 1 (Proprietary), WCAP-8312-A (Nonproprietary), "Westinghouse Mass and Energy Release Data For Containment Design," August 1975

increase the subcompartment pressure. However, the reduction in break size due to credit for leak-before-break offsets the effect of coolant temperature and the net result is a lower subcompartment pressure. The subcompartment loads are therefore bounded by the current licensing basis described in the PTN UFSAR.

Since the current licensing basis analysis for the subcompartment analysis bounds the proposed EPU conditions, the license renewal scope, aging effects, and aging management programs for the components within the scope of the analysis remains the same. Based on the information provided by the licensee, the NRC staff concludes that the EPU will have no impact on license renewal as it relates to subcompartment analysis.

Conclusion

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased mass and energy release. The 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 GDCs 4 and 50 for the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to subcompartment analyses.

2.6.3 Mass and Energy Release

Mass and Energy Release Analysis for the Postulated Loss-of-Coolant Accident

Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including subcompartments and systems within the containment. The NRC staff's review covered the energy sources that are available for release to the containment and the mass and energy release rate calculations for the initial blowdown phase of the accident. The NRC's acceptance criteria for mass and energy release analyses for postulated LOCAs are based on: (1) GDC-50, insofar as it requires that sufficient conservatism be provided in the mass and energy release analysis to assure that containment design margin is maintained; and (2) 10 CFR Part 50, Appendix K, insofar as it identifies sources of energy during a LOCA. Specific review criteria are contained in SRP Section 6.2.1.3.

NRC Technical Evaluation

The long-term LOCA mass and energy releases were analyzed for PTN to the end of the refueling water storage tank draindown using NRC-approved Westinghouse methods.[70] The model comprises M&E release versions of the codes SATAN VI for blowdown phase;

[70] WCAP 10325-P-A, Westinghouse LOCA Mass and Energy Release Model for Containment Design, March 1979 and WCAP 8264-P-A, "Topical Report Westinghouse Mass and Energy Release Data Containment Design," Revision 1, August 1975

WREFLOOD for the core reflooding phase when ECCS water refills the reactor vessel and ends when the core is completely quenched; FROTH for the post-reflood portion of the transient until the time that the secondary side of the intact loops' SG has depressurized to the containment design pressure; and EPITOME, which continues the FROTH post-reflood portion of the transient to the start of cold leg recirculation for the minimum safeguards double ended pump suction break scenario. The long-term post-3600 second, M&E release calculations are performed through user-defined functions by GOTHIC. These input functions are used to incorporate the sump water cooling in the long term and are consistent with the Westinghouse GOTHIC methodology approved by the NRC.

Westinghouse identified an issue with the computer code, EPITOME, as it related to PTN LOCA M&E release analysis originally submitted in letter dated October 21, 2010, for the EPU. Westinghouse identified this issue as a result of an inconsistency in calculations performed by the EPITOME computer code that impacts post blowdown LOCA M&E calculations. Westinghouse states that this error only impacts the double ended pump suction (DEPS) break. As a result of this issue, the EPITOME computer code has been revised, and the modifications made to the code do not invalidate the staff's safety evaluation report (SER) for WCAP 10325-P-A.

By letter dated July 22, 2011,[71] the LOCA M&E release analysis and associated containment integrity analysis were revised by the licensee to address the specific issue identified above. The calculated LOCA mass and energy releases are inputs to the LOCA containment analyses discussed in Section 2.6.1 of this safety evaluation report.

The core rated thermal power assumed for these calculations is 2652 MWt. This is 100.3 percent of the EPU thermal power of 2644 MWt, which includes a 0.3 percent measurement uncertainty. The 0.3 percent measurement uncertainty includes allowance for additional calorimetric error. The licensee has also used American Nuclear Society (ANS) Standard 5.1-1979, "American National Standard for Decay Heat Power in Light Water Reactors," August 29, 1979, with a 2σ uncertainty and other assumptions which maximize the decay heat added to the coolant.

A PTN plant-specific decay heat curve for the reflood phase and long term was generated for use in the revised LOCA analysis. The blowdown phase M&E releases continue to be based on the generic Westinghouse decay heat curve. The reflood phase releases and the long-term decay heat are based on the PTN plant-specific decay heat curve. The curve is slightly reduced from the previously used curve, for times less than approximately 10,000 seconds. The applicability of the PTN plant-specific decay heat curve is confirmed each cycle as part of the normal reload safety analysis checklist (RSAC) process.

Section 2.6.3.1.2.1.2 of the LR describes the assumptions and input used for the LOCA mass and energy release calculations. The staff has reviewed the input and assumptions and concludes that they are sufficiently conservative. For example, in addition to the 0.3 percent uncertainty on rated thermal power, the licensee has bounded the reactor coolant system operating temperature and initial pressure. This maximizes the mass and energy release. The core stored energy is maximized by assuming the time in fuel life of maximum densification.

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[71] ML11207A456

The reactor coolant system volume is increased by 3 percent to account for dimensional uncertainty and thermal expansion. This provides more mass to be released. No steam generator tube plugging is assumed. This also maximizes the reactor coolant system inventory as well as the steam generator tube heat transfer area. A critical flow rate correlation and assumptions which reduce flow resistance maximize the break flow rate. The staff, therefore, considers the input and assumptions for the mass and energy release to the containment to be acceptably conservative.

The licensee included the following sources of mass addition to the containment:

RCS water
Accumulator water
Pumped injection

The licensee included the following sources of energy addition to the containment:

RCS water
Accumulator water
Pumped safety injection
Decay heat
Core-stored energy
RCS metal including steam generator tubes
Steam generator metal in contact with secondary side fluid
Steam generator secondary energy
Feedwater into and steam out of steam generator secondary

The staff considers these mass and energy sources to be acceptably complete.

The licensee states that energy from the zirconium-water reaction was not included because the energy release from the fuel rod is maximized for this calculation. Therefore, the cladding does not reach the temperature at which the zirconium-water reaction is significant. This is acceptable since it maximizes the fuel stored energy released to containment.

The single failure assumptions are discussed in Section 2.6.1 of this safety evaluation report. The staff finds them acceptable, as discussed in that section.

There are no specific criteria for the mass and energy release calculation results. Acceptable calculated peak containment pressures and temperatures demonstrate acceptability of the mass and energy release calculations. For PTN at EPU conditions, these results are acceptable as discussed in Section 2.6.1 of this safety evaluation report input.

The licensee evaluated the long-term LOCA M&E releases under EPU conditions and determined that it has no effect on license renewal system evaluation boundaries. Further, the analytical results of the containment response do not add any new or previously unevaluated aging effects that necessitate a change in aging management programs or require a new program that would affect the system boundaries for license renewal. Based on this information, the NRC staff concludes that the long-term LOCA M&E releases at EPU conditions will have no impact license renewal.

Conclusion

The NRC staff has reviewed the licensee's mass and energy release assessment and concludes that the licensee has adequately addressed the effects of the proposed EPU and appropriately accounts for the sources of energy identified in 10 CFR Part 50, Appendix K. Based on this, the NRC staff finds that the mass and energy 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 mass and energy release for postulated LOCA.

Mass and Energy Release Analysis for Secondary System Pipe Ruptures

Regulatory Evaluation

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

NRC Technical Evaluation

The licensee performed analyses of the containment response to the main steamline break analysis in support of the EPU. Major elements considered in this analysis that are different from the current licensing-basis analysis are the modification of the existing motor-controlled main feedwater isolation valves (FIV) to serve as an automatic back-up to the feedwater control valves (FCV), the addition of a backup valve in the main feedwater (MFW) bypass line, and the addition of a lead/lag on the low steamline pressure setpoint.

The major input assumptions for the containment analyses, the secondary side systems, and the reactor coolant system are listed in Attachment 4 of the Licensing Report. In response to a NRC staff RAI, the licensee in a letter dated April 28, 2011,[72] provided a summary of the key inputs to the MSLB analysis, in particular, all changes to the inputs, assumptions, single failures, MFW flow rates, valve isolation times, AFW flow rates, AFW pump start times, and the codes used in the analysis, between the pre-EPU and the EPU conditions. The NRC staff's review indicates the changes are consistent with the proposed modifications, and therefore, are acceptable.

In addition, in the licensee's RAI response dated April 28, 2011, the licensee created a table that summarizes the key inputs to the MSLB analysis, in particular, all changes to the inputs,

[72] ML11119A135

assumptions, single failures, AFW flow rates, AFW pump start times, and the codes used in the analysis.

The main steamline break M&E release and containment response analyses does not utilize the EPITOME code and are not directly impacted by the issues discussed in the previous section, Mass and Energy Release Analysis for the Postulated Loss-of-Coolant Accident. However, the main steamline break analyses were revised to address some of the other input considerations described in letter dated July 22, 1011. Specifically, those input considerations that are applicable to the main steamline break are containment volume, initial containment temperature, initial containment pressure, initial containment relative humidity, and spray droplet size. The remaining changes were either specific to the LOCA analysis or remained conservative in the main steamline break analysis.

The licensee performed main steamline break calculations to support the proposed EPU using NRC-approved methods for the mass and energy release into the containment. The RETRAN code, used in this analysis for mass and energy release, was approved by the NRC in WCAP-14882-P-A, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," April 1999. GOTHIC 7.2a was used for the containment response analysis, in accordance with methods previously approved in Ginna license amendment by letter dated July 11, 2006.[73] When used in this way, the heat transfer model is referred to as the diffusion layer model.

The licensee stated that the PTN GOTHIC model was benchmarked against the existing PTN COCO model. COCO is the Westinghouse computer code used for the current containment safety analyses in the PTN UFSAR.

Section 2.6.3.2.2.2 of the LR describes the inputs and assumptions used in the analyses. These include the assumed power levels at which the main steamline break may occur (100.3, 70, 30, and 0 percent), single failure assumptions, and containment description used in the analyses. The break cases considered are full double ended ruptures (DERs) and split breaks. All breaks are located immediately downstream of the flow restrictor at the outlet of the SG. The staff has reviewed the licensee's input and assumptions and finds them acceptable since they cover a spectrum of power levels and single failures and conservatively model the containment for main steamline break accidents.

Section 2.6.3.2.2.5 of the LR provides the results of the licensee's main steamline break accident calculations for the most limiting conditions. The limiting conditions include: the EPU level of 2652 MWt, shutdown margin of 1.77 percent, and the failure of a main steamline check valve (the worst single failure) which results in a nonreturn check valve on the faulted loop failed open. An initial power level of 0 percent, coupled with a 1.0 ft^2 split break gave the most limiting containment pressure results. The limiting containment pressure case for the EPU is 1.0 ft^2 split break.

The licensee calculates for this case that the peak containment pressure is 53.4 psig which is less than the containment design pressure of 55 psig.

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[73] ML061380103

The licensee's calculations supporting the EPU changes were done with acceptable methods and conservative input and assumptions and are, therefore, acceptable.

The licensee evaluated the containment response to the MSLB under EPU conditions (including mass and energy releases) and determined that it has no effect on license renewal system evaluation boundaries. Further, the analytical results of the containment response do not add any new or previously unevaluated aging effects that necessitate a change in aging management programs or require a new program that would affect the system boundaries for license renewal. Based on this information, the NRC staff concludes that the containment response to the MSLB at the proposed EPU conditions will have no impact on license renewal.

Conclusion

The NRC staff has reviewed the mass and energy release assessment performed by the licensee for postulated secondary system pipe ruptures and finds that the licensee has adequately addressed 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 mass and energy release for postulated secondary system pipe ruptures.

2.6.4 Combustible Gas Control in Containment

Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excessive hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The NRC staff's review covered (1) the production and accumulation of combustible gases, (2) the capability to prevent high concentrations of combustible gases in local areas, (3) the capability to monitor combustible gas concentrations, and (4) the capability to reduce combustible gas concentrations. The 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 and 10 CFR 50.46 for plants being designed to prevent the development of combustible mixtures in the containment atmosphere; (2) GDC-5, for shared systems and components important to safety being able to perform their required safety functions; and GDCs 41, 42, and 43 for systems being provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure containment integrity is maintained. Specific review criteria are contained in SRP Section 6.2.5.

NRC Technical Evaluation

On December 20, 2001,[74] the NRC approved an exemption request at PTN for the hydrogen recombiner and the post-accident containment vent system and the deletion of associated technical specifications for these systems, including the deletion of post-accident monitoring instrumentation from the TS.

On September 16, 2003, the NRC revised 10 CFR 50.44, "Standards for combustible gas control system in light-water-cooled power reactors." Requirements for hydrogen recombiners and hydrogen purge systems were eliminated and requirements on the hydrogen and oxygen monitoring systems were relaxed.

The licensee states in the LR that:

> Based on the limited exemption to 10 CFR 50.44 requirements and the license amendment approved by the NRC on December 20, 2001, the containment combustible gas control system and its components are no longer part of the PTN licensing and design basis. FPL concludes that any post-accident hydrogen generation at the proposed EPU conditions does not require further evaluation and that reliable equipment is provided to continuously monitor post-accident hydrogen concentration, consistent with the requirements of 10 CFR 50.44(b)(4)(ii).

The staff finds this acceptable and consistent with the intent of revision to 10 CR 50.44.

In response to a staff's request for additional information, regarding the EPU impact on the ECCS ability to provide homogenous atmospheric mixing, specifically post-LOCA, the licensee discussed the layout and arrangement of the containment internal structures, and active and passive mixing mechanisms. The licensee's assessment demonstrates that containment design allows air to circulate freely, and that passive mechanisms such as convective mixing in conjunction with active systems such as containment spray (CS) and operation of the emergency containment coolers (ECC) system ensure a mixed atmosphere inside containment thus precluding accumulation of a combustible or explosive mixture within a compartment or cubicle.

The staff finds the licensee's response to ensuring a mixed atmosphere following a LOCA at EPU conditions acceptable and consistent with the requirements of Section (b)(2) of 10 CFR 50.44.

The licensee evaluated the post-accident hydrogen monitoring and control systems 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 aging management programs. The licensee states that the EPU does not add new or previously unevaluated effects that necessitate a change in aging management programs or require a new program that would affect the system boundaries for license renewal.

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[74] Letter from NRC to FPL, "Turkey Point Units 3 and 4 – Issuance of Amendments Regarding Deletion of TS for Hydrogen Monitors and Post-Accident Containment Vent System," December 20, 2001

Conclusion

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

2.6.5 Containment Heat Removal

Regulatory Evaluation

Fan cooler systems, spray systems, and residual heat removal (RHR) systems are provided to remove heat from the containment atmosphere and from the water in the containment sump. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler heat exchangers. The NRC's acceptance criteria for containment heat removal are based on GDC-38, insofar as it requires that the containment heat removal system be capable of rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. Specific review criteria are contained in SRP Section 6.2.2 and RG 1.82, Revision 3.

In regards to NPSH of the ECCS and containment heat removal pumps, the NRC staff's review is focused on whether the licensee proposes to rely on containment accident pressure (CAP) to assure adequate NPSH, uncertainties in NPSH required (NPSHR) and operation in the maximum erosion zone. The review is based on draft guidance provided by the staff in a letter dated March 24, 2010[75] to the Pressurized Water Reactor Owner's Group.

NRC Technical Evaluation

In response to a staff request, FPL in a letter dated May 26, 2011,[76] provided the results of NPSH evaluations performed at the proposed EPU conditions for the high head safety injection (HHSI) pumps, containment spray (CS) pumps, and the residual heat removal (RHR) pumps. The evaluations were performed for the safety injection phase with pump suction from the refueling water storage tank (RWST) and during the recirculation phase when the RHR pump takes suction from the containment sump. During the recirculation phase, the HHSI and CS pump suctions are aligned to the RHR pump discharge, thus resulting in available NPSH to the HHSI and CS pumps substantially above the NPSHR.

The licensee stated that the basis for the NPSHR of the RHR, HHSI, and CS pumps is the NPSHR curve from each of the vendor pump test curves, and the basis for the NPSHR curves

[75] Letter from NRC to PWROG, "The Use of Containment Accident Pressure in Demonstrating Acceptable Operation of Emergency Core Cooling and Containment Heat Removal Pumps During Postulated Accidents," March 24, 2010 (ML100740516)
[76] ML11151A203

is the 3 percent head drop value, which is standard for factory tests of the pumps. The licensee indicated that NPSH analysis flows were assumed for the limiting system alignment for each pump during safety injections and that these flows fall on the NPSHR curves for tested flows, and no curve extrapolation was necessary.

By letter dated May 26, 2011, the licensee described the method used for calculating NPSH available (NPSHA) as the "classical" method of calculating NPSH, and provided the assumptions used in arriving at a conservative NPSHA:

> The suction source elevation (RWST or sump) is minimized for the specific system alignment, and the water source surface pressure is assumed to be the saturation pressure of the liquid. By making this assumption, the atmospheric pressure and the vapor pressure terms in the NPSHA equation cancel out, and no credit is taken for elevated pressure at the liquid surface. The pump flow rate is maximized to result in a conservatively high NPSHR from the vendor pump curve, and a high flow rate through the suction piping losses are calculated to minimize the NPSHA.

The results of the NPSH evaluation for the injection phase show that in all cases, the available NPSH exceeded the required NPSH for the RHR, HHSI and CS pumps at EPU conditions.

During the recirculation phase, the limiting alignment for the RHR pump is during the cold leg recirculation with two HHSI pumps and one CS pump operating. As stated earlier, the RHR pump takes suction from the sump and discharges into the suction of the HHSI and CS pumps in a "piggy-back" alignment. The licensee stated that for the EPU conditions, two HHSI and one CS pump must be operating during recirculation. For the EPU, plant operating procedures will assure that only one RHR pump, two HHSI pumps, and one CS pump are running during the recirculation phase.

The uncertainties in NPSHR included in the staff's guidance[77] address the possibility that conditions during the NPSHR vendor tests could be different than those by the pumps during operation at the plant, effectively increasing the NPSHR values. The differences could arise due to pump inlet temperature variation, pump inlet geometry variation, dissolved gas evolution, increase in mechanical wear ring clearance, etc. Based on an NRC pump consultant report on uncertainties, an average variation in the NPSHR of between +9 percent to +21 percent could be expected depending on the differences in installation and operation between the NPSHR test and plant conditions. The staff conservatively elected to use a 21 percent margin on the $NPSHR_{3\%}$ as a bounding estimate in this review, denoted as NPSHR effective ($NPSHR_{eff}$), and advised FPL that it may use this value for PTN in-lieu of plant specific evaluations or testing to determine the uncertainty. FPL opted to use the 21 percent uncertainty on NPSHR in their NPSH evaluations. The information provided by FPL shows that the HHSI pump during the safety injection phase and the RHR pump during the recirculation phase have the least margins at 20.7 percent and 19.2 percent, respectively. Even though the margins are less than 21 percent, based on the conservative evaluations by the licensee (e.g. maximum NPSHR with minimum NPSHA), the NRC staff considers them acceptable since the licensee has not

[77] NRC Draft Guidance For The Use Of Containment Accident Pressure In Determining The NPSH Margin Of ECCS And Containment Heat Removal Pumps (ML100550869)

included the partial pressure of the air in containment in the available NPSH calculation. The NRC staff also finds the licensee's NPSH evaluations acceptable as they are consistent with the recommended approach in the staff's guidance.

Containment heat removal is addressed in Section 2.6.1 of this SE. Included in that discussion, is the staff's evaluation of the licensee's single failure assumptions for the containment recirculation fan coolers and the containment spray systems. As noted in Section 2.6.3 of this safety evaluation, the licensee uses the ANS 5.1-1979 decay heat model with a 2σ uncertainty included. This is conservative and acceptable.

The licensee evaluated the containment heat removal systems 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 aging management programs. The licensee states that the EPU does not add new or previously unevaluated effects that necessitate a change in aging management programs or require a new program that would affect the system boundaries for license renewal. Based on the information provided by the licensee, the NRC staff concludes that the proposed EPU will have no impact on 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 NRC staff finds that the systems will continue to meet GDC-38 for rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. The staff also concludes that PTN has adequate NPSH to the ECCS pumps and that it also meets the staff's guidance on NPSH uncertainty and operation in maximum erosion zone. Therefore, the NRC staff finds the proposed EPU acceptable with respect to containment heat removal systems.

2.6.6 Pressure Analysis for ECCS Performance Capability

Regulatory Evaluation

Following a loss-of coolant accident (LOCA), the emergency core cooling system (ECCS) will supply water to the reactor vessel to reflood the reactor core 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 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 use of an acceptable emergency core cooling system evaluation model that realistically describes the behavior of the reactor during LOCAs, or an emergency core cooling system evaluation model developed in conformance with 10 CFR Part 50, Appendix K. Specific review criteria are contained in SRP Section 6.2.1.5.

NRC Technical Evaluation

In the best estimate ECCS evaluation model, the containment pressure transient is provided as a boundary condition to the system hydraulic transient. The containment pressure transient applied should be conservatively low and include the effects of the operation of all pressure reducing systems and processes. As specified in 10 CFR Part 50, Appendix K, the containment pressure used for evaluating cooling effectiveness during reflood and spray cooling shall not exceed a pressure calculated conservatively for this purpose.

The licensee performed the containment backpressure analysis for a large break LOCA using the COCO computer code[78] to generate the containment pressure response using the mass and energy release from the break from a reference WCOBRA/TRAC transient. The application of the old code is consistent with Westinghouse Emergency Core Cooling System Evaluation Model Summary, WCAP-8339 Appendix A, June 1974. The licensee provided in Table 2.6.6-1 of the LR, key input parameters used in the containment backpressure analysis. The parameters are consistent with the guidance in Branch Technical Position (BTP) 6.2, Rev. 3. This containment pressure curve is then used to determine an appropriate input to the WCOBRA/TRAC code as sanctioned by the large break LOCA evaluation model at EPU conditions. As shown in LR Figure 2.6.6-1, the containment pressure curve used as an input to the WCOBRA/TRAC code for the thermal-hydraulic calculations is at a lower pressure than the containment pressure curve calculated by the COCO computer code.

By letter dated April 28, 2011, the licensee provided a figure reflecting the minimum containment pressure response during reflood for the current licensing basis and the EPU. As expected, the containment backpressure is greater than that of the non-uprated conditions and the NRC staff finds this acceptable.

The licensee evaluated the pressure analysis for ECCS performance capability 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 aging management programs. The NRC staff concurs that the activities performed under pressure analysis for ECCS performance capability will not impact the license renewal.

Conclusion

The NRC staff has reviewed the pressure analysis for ECCS performance capability provided by the licensee and concludes that the licensee has adequately addressed the effects of the proposed EPU. The NRC staff finds that the system will continue to meet 10 CFR 50.46 for use of an acceptable emergency core cooling system evaluation model with respect to minimum containment pressure analysis for ECCS performance.

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[78] F. M. Bordelon and E. T. Murphy, Containment Pressure Analysis Code (COCO), WCAP-8327 (Proprietary Version), WCAP-8326 (Non-Proprietary Version), June 1974

2.6.7 Additional Review Areas

Generic Letter 96-06

Regulatory Evaluation

Generic Letter 96-06[79] addressed the issue of overpressurization of containment piping penetrations due to thermal expansion of fluid between closed isolation valves.

GDC 50 requires that the reactor containment structure, including access openings, penetrations, and the containment heat removal system shall be designed so that the containment structure and its internal compartments can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature from any LOCA.

NRC Technical Evaluation

An EPU has the potential for affecting the licensee's response to Generic Letter 96-06. During the licensee's initial GL 96-06 evaluation, some pipe sections were identified to not either have self relieving capabilities or were not drained / partial filled. Modifications were made to these pipe sections by installing thermal relief valves, partially draining the piping system, or modifying valves to prevent entrapped water from causing an overpressurization condition due to external heat. By letter dated April 28, 2011, the licensee stated that the EPU will not require any modifications to these pipes.

In addition, all component cooling water (CCW) system branch lines that penetrate containment (i.e. inlet and outlet) and feed the emergency containment coolers, normal containment coolers, reactor coolant pump bearing/thermal barrier coolers and the excess letdown heat exchanger are either isolated or may be isolated during an accident, making them susceptible to GL 96-06 concerns. The licensee stated that thermal relief valves have been installed or relief valves were verified to be installed to protect these CCW system branch lines from overpressurization.

The licensee stated that no new piping configurations that penetrate containment and have the potential to overpressurize due to thermal expansion of the fluid have been created as a result of the EPU.

Conclusion

The NRC staff has reviewed the licensee's compliance with the recommendations of GL 96-06 with respect to the EPU. The licensee has demonstrated that, in accordance with GDC 50, the containment penetrations will not be overpressurized by an increase in containment temperature at EPU conditions as a result of a postulated design basis accident.

[79] NRC Generic Letter 96-06: Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions, September 30, 1996

Generic Safety Issue 191

Regulatory Evaluation

The NRC Generic Safety Issue (GSI)-191 addresses the issue of post-accident debris generation and the resultant impact on the sump strainer.

10 CFR 50.46 (b)(5) and Appendix A to 10 CFR Part 50, Criterion 35 requires long term emergency core cooling.

NRC Technical Evaluation

By letter dated May 26, 2011, the licensee stated that parameters affecting the zones of influence are dependent on the geometry of the RCS piping, but independent of RCS operating conditions such as pressure and temperature. The NRC staff is not in agreement with the licensee's statement, however, concludes that the change in pressure and temperature at the EPU conditions would have a negligible impact on the current zones of influence. The licensee stated that the EPU has no impact on post-accident containment sump flow rates and debris transport and that the recirculation phase flows are driven by break size, location, and the flow rates of the ECCS and CS pumps, which are not a function of RCS operating parameters or post-LOCA decay heat rates. The staff agrees with the licensee's statement that EPU flow rates for the ECCS and CS pumps will be maintained within the design flow rates used for the sump design.

Additionally, the licensee stated that the EPU has no impact on post-accident containment sump conditions relevant to GSI-191. Marginal increases in sump level and temperature resulting from EPU are bounded by existing analyses for GSI-191.

The licensee indicated that the EPU impact on post-accident debris generation with respect to GSI-191 will be bounded by the ongoing GSI-191 resolution. In addition, changes made to debris loading resulting from EPU modifications (including beneficial changes such as reductions in fiber, calcium silicate, aluminum quantities), will be considered in the ongoing GSI-191 resolution.

Conclusion

The NRC staff evaluations of GSI-191 are ongoing for many PWRs including PTN Units 3 and 4. However, the operating fleet of PWRs is allowed to continue operations based on the current state of resolution, while the NRC staff and the PWR licensees continue their work to resolve any remaining open items. The NRC staff agrees with the licensee's statement that all future evaluations related to GSI-191, including debris will include both the current and EPU conditions.

Technical Specifications Changes

The NRC has reviewed the licensee's proposed changes to TS 3.6.1.4, "Containment Systems – Internal Pressure." The current TS 3.6.1.4, requires the primary containment internal pressure

to be maintained between -2 and +3 psig. The proposed change to TS 3.6.1.4 requires the primary containment internal pressure to be maintained between -2 and +1 psig.

The licensee stated that additional margin between the design basis containment pressure and the peak design basis containment pressure was required as a result of the EPITOME M&E/Containment Analysis error. Specifically, a lower maximum primary containment internal pressure of +1 psig is used as an initial condition in both the LOCA and MSLB containment integrity analyses and results in lower post accident peak containment pressure. The lower containment pressure is more restrictive and will assure that the accident peak containment pressure remains within design limits.

The EPU DBA-LOCA and MSLB analyses were performed using the maximum primary containment internal pressure of +1 psig as an initial condition. As discussed in this safety evaluation, the results of both sets of analyses satisfied all applicable safety criteria. Therefore, with respect to containment safety analyses, the proposed changes to these limiting safety system settings are acceptable.

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

The Nuclear Regulatory Commission (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 extended power uprate (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 the following general design criteria (GDC) from Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants": (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 NRC's NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (SRP or Standard Review Plan), Section 6.4.

NRC Technical Evaluation

The licensee evaluated the effects of EPU on the control room habitability systems during normal and emergency operation and states that EPU would not cause any significant changes to the control room envelope integrity, 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.

The licensee states that no modifications are performed for EPU that would significantly increase the equipment heat loads internal to the control room in comparison to the overall load and equipment capacity. The evaluation of the control room ventilation system (CRVS) to provide cooling to the control room under EPU conditions is provided in Section 2.7.3. The licensee also states that EPU will not create additional fire or chemical mishap scenarios that have not been previously evaluated for the CRVS. The analysis of the CRVS carbon filter for EPU post-loss of coolant accident (LOCA) conditions is provided in Section 2.7.2. The licensee has documented the EPU radiological consequences evaluation and results in Section 2.9.2 of the LR, and the NRC staff has documented its review of the radiological consequences in Section 2.9.2 of this safety evaluation (SE).

The TSC at Turkey Point Nuclear Plant (PTN) is not part of the control room envelope (CRE). It is located in a separate structure and equipped with a high efficiency filtration system.

The licensee evaluated the CRE, CRVS, and TSC 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 aging management programs. The licensee states that the EPU does not add new or previously unevaluated effects that necessitate a change in aging management programs or require a new program that would affect the system boundaries for license renewal. Based on the information provided by the licensee, the staff concludes that EPU will have no impact on CRE, CRVS and TSC cooling system.

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. Based on the information provided by the licensee, the EPU would not result in any change to the toxic gas releases evaluated under the current licensing basis. Further, the NRC staff concludes that the licensee has adequately accounted for the increase of radioactive gases that would result from 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.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

Regulatory Evaluation

Engineered Safety Feature (ESF) atmosphere cleanup systems are designed for fission product removal in post-accident environments. These systems generally include primary systems (e.g., in containment recirculation) and secondary systems (e.g., emergency or post-accident air cleaning systems) for the fuel handling building, control room, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the NRC staff's review 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 anticipated operational occurrences (AOOs), and postulated accidents. Specific review criteria are contained in Standard Review Plan, Section 6.5.1.

NRC Technical Evaluation

The systems that are included in the ESF atmosphere cleanup systems are: (1) containment spray (CS) system, (2) emergency containment coolers (ECCs), (3) auxiliary building ventilation system, (4) control room ventilation system (CRVS) and (5) spent fuel area ventilation 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.

PTN's original design credited the emergency containment filtering (ECF) system and not the CS system with reducing the iodine concentration in the containment atmosphere following a maximum hypothetical accident in order to assure that off-site dose would not exceed the applicable regulatory limits at the site boundary. The PTN License Amendment Request (LAR) No. 196 approved by the NRC staff by letter dated June 23, 2011,[80] reanalyzed PTN's design basis accidents (DBAs) for radiological consequences using the AST methodology and credits the CS system for reducing the iodine concentration for the maximum hypothetical accident while eliminating the ECF system and its associated charcoal adsorption beds from the plant's design basis. The licensee stated that the ECF system components would either be removed or abandoned in place. The AST evaluation was performed at the EPU conditions with the assumption that certain modifications required in support of the inputs to the AST evaluation will be implemented prior to the AST implementation. As stated in Section 2.9.2 of the LR, they include:

1. Installation in the containment basement of stainless steel wire-mesh baskets filled with sodium tetraborate decahydrate (NaTB).

2. Relocating the control room emergency ventilation system dual air intakes to near the ground level of the southeast and northeast corners of the auxiliary building. The relocated intakes will be designed to seismic criteria, protected from environmental effects, and will meet the requirements of 10 CFR Part 50 Appendix A, GDC 19.

[80] ML110800666

3. Installing a new compensatory filtration unit as a backup to the existing CREVS filter train.

4. Adding isolation dampers to the kitchen and lavatory exhaust ducts in the control room ventilation system.

In regard to the ECCs, the current radiological analyses and the AST assume that the containment air volume within the containment building is mixed by the ECC System fans to support the iodine removal function performed by the CS System. In letter dated April 28, 2011, the licensee provided information in support of the homogeneous atmospheric mixing within containment under DBA-LOCA conditions. The assessment was based on layout and arrangements of the internal structures, natural buoyancy driven convective flows, forced convection generated by the CS system, and enhanced mixing as a result of the ECCs. As part of EPU, the licensee stated that two of the three ECCs will be in operation under DBA-LOCA, compared to one ECC under the current licensing basis.

As described in LR section 2.7.3, the CRVS conditions the CR air and supplies fresh makeup air to maintain safe levels of oxygen under normal and emergency conditions. The system maintains a positive pressure in the control room. It also limits the airborne radioactivity in the CR during emergency conditions by passing a portion of the recirculation control room air through HEPA filters and charcoal adsorbers. The dose analysis for EPU operation is discussed in Section 2.9 of this SE. As stated in LR section 2.7.2, the licensee performed an analysis of the temperature effects on the CRVS carbon filter due to decay heat at the post-EPU LOCA conditions. The maximum temperature occurs after the emergency mode of the CRVS is exited and the carbon filter is no longer ventilated. The licensee stated that CRVS carbon filter temperature was found to be within design limits for this scenario.

The licensee stated that, as described in UFSAR Section 9.8.1, the auxiliary building ventilation system is nonsafety-related, and no credit is taken for removal of iodine nor is credit taken for isolation of release paths. Auxiliary building ventilation is provided by dual supply and exhaust fans that ventilate the area and exhaust through HEPA filters to the atmosphere via the plant stack. The plant stack is a monitored release path. Operation of this system would be interrupted by a loss of normal power supplies; however, the fans can be manually loaded onto the emergency diesel generators.

Similar to the plant stack monitoring system, the independent radiation monitoring instrument of the PTN Unit 3 spent fuel pool system effluent is not affected by the EPU. Aside from the PTN Unit 3 spent fuel pool area ventilation system effluent radiation monitoring function, neither the Unit 3 nor Unit 4 spent fuel pool area ventilation systems perform any post-accident function. Therefore, the spent fuel pool area ventilation systems are not credited in containing radioactive releases.

The staff did not identify any modifications or additions to ESF and emergency atmospheric cleanup system components as the result of EPU that would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. Operation of the ESF and emergency atmosphere cleanup systems at

EPU conditions does not add any new types of materials or previously unevaluated materials to the system.

As described in the NRC's SE dated June 23, 2011, on the PTN AST, the staff evaluated the ESF atmospheric cleanup systems under post-EPU conditions. These systems will continue to provide adequate mixing, steam removal, and fission product removal within the containment atmospheres in the event of a LOCA or main steamline break (MSLB). The EPU has no effect on the ability of the PTN 3 and 4 emergency atmosphere cleanup systems to control the release of radioactivity to the environment within regulatory limits. The CRVS carbon filter will continue to be within design limits for EPU post-LOCA conditions. The EPU does not require modifications to the equipment or operation of any of the ESF and emergency atmospheric cleanup systems that are in effect with the advent of AST implementation. The ESF and emergency atmospheric cleanup systems will continue to comply with the cited regulatory criteria for the post-EPU plant configuration.

The licensee evaluated the ESF and emergency atmospheric cleanup system 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 aging management programs. The licensee states that the EPU does not add new or previously unevaluated effects that necessitate a change in aging management programs or require a new program that would affect the system boundaries for license renewal. Based on the information provided by the licensee, the NRC staff concludes that the EPU will have no impact on ESF and Emergency Atmospheric Cleanup system.

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 GDCs 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 Control Room Area Ventilation System

Regulatory Evaluation

The function of the control room area ventilation system (CRAVS) is to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components during normal operation, AOOs, and DBA conditions. At PTN, the CRAVS is referred to as the control room ventilation system (CRVS). The NRC's review of the CRVS 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 CRVS. The NRC's acceptance criteria for the CRVS 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 Standard Review Plan, Section 9.4.1.

NRC Technical Evaluation

The CRVS serves the control room envelope (CRE) by continuously filtering and conditioning the atmosphere in the CRE. The cooling and circulating portions of the system consists of air circulating ducts, three 100 percent capacity air handling units and associated condensing units. One unit can maintain the control room environment within the design limits of the equipment located in the control room. At least two air handlers and one compressor is needed to keep the control room habitable for the operators. The configuration of the power sources and the emergency diesel generators preclude the loss of more than one unit for postulated single failures. During normal conditions, the system continuously recirculates, filters, and cools the control room air with a small amount of outside air drawn into the system. Under emergency conditions, the system goes into a recirculating mode in which all the exhaust fans shut off and the intake and exhaust dampers close, the primary purpose being to control the intake of airborne activity. In the event of an emergency, the CRVS has two emergency modes of operation: (1) Automatic - initiated upon receipt of applicable signals associated with a potential radiological exposure and (2) Manual – initiated by the CR operator. For the LOCA analysis, the CR ventilation system is initially assumed to be operating in normal mode. The air flow assumed during the normal mode of operation is 1000 cubic feet per minute (cfm) of unfiltered fresh air make-up and an unfiltered inleakage of 100 cfm. After the start of the event, the CR will be isolated on either a safety injection signal, or a high radiation signal from either the containment or the normal CR intake. The licensee applied a 30-second delay to account for the time required to reach the signal, the time to start the diesel generator and the time for damper actuation. After CR isolation, the air flow distribution is assumed to consist of 525 cfm of filtered makeup flow from the more limiting of the two emergency outside air intakes, 100 cfm of assumed unfiltered inleakage, and 375 cfm of filtered recirculation flow. The licensee assumed a CR ventilation filter efficiency of 99 percent for particulates and 95 percent for elemental and organic iodine for both the filtered makeup and the recirculation flow.
These analyses provide for a bounding allowable CR unfiltered air inleakage of 100 cfm. The use of 100 cfm as a design basis value is expected to be above the unfiltered inleakage value to be determined through testing or analysis consistent with the resolution of issues identified in Nuclear Energy Institute (NEI) guidance document NEI 99-03, “Control Room Habitability Assessment Guidance,” Revision 0, June 2001 and Generic Letter 2003-01, “Control Room Habitability” June 12, 2003. CR inleakage testing performed at PTN in 2003 indicates less than 10 cfm of unfiltered inleakage providing a significant margin between the bounding dose analysis inleakage value of 100 cfm and the measured CR unfiltered inleakage.

On April 1, 2011, the NRC staff requested additional information regarding Section 2.5.3 “Fission Product Control” of the licensee’s LR dated October 21, 2010. Specific to the CRVS, the licensee was asked to clarify the discrepancy in the filter removal efficiency and in-leakage

flow parameters discussed in subsection 2.5.3.2.2 of Attachment 4 of the LR with that of the previously approved AST application. Based on the licensee's response in a letter dated April 28, 2011, the NRC staff is satisfied that consistent and acceptable values were used by the licensee for the filter efficiency and unfiltered inleakage.

The NRC staff further asked the licensee to provide a summary of the CRVS heat removal evaluation performed for the EPU, discuss any changes in CR heat loads, and specify if the evaluations performed are qualitative or quantitative. By letter dated April 28, 2011, the licensee stated that the CRVS evaluation was a qualitative analysis. The CRVS was evaluated to determine the impact of EPU conditions on the existing cooling capacity. The CRVS was evaluated by reviewing the pre-EPU design and examining any changes to the CRVS heat loading as a result of EPU. The heat loads in the CRVS are not a function of reactor power level, but are from electrical control equipment within the CR, ambient outside air temperatures and personnel. The EPU modifications will revise a small minority of existing control room indicators. The revisions to these indicators will cause a negligible impact on the overall instrument and control circuit current loading and dissipated heat experienced within the control room heating, ventilation, and air conditioning (HVAC) system envelope. These changes will therefore have a negligible impact on the ability of the control room HVAC system to maintain the required temperature. The NRC considers the licensee's response reasonable, and therefore, concludes that the licensee has adequately addressed any heat load changes in the CRE as a result of the proposed EPU.

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.

The licensee stated that in all modes of operation, the CRE is maintained radiologically benign for the sake of continuous habitability and that air effluents from the CRVS, whether from exhaust fans or ex-filtration, will continue to be nonradioactive in the post-EPU plant configuration. Additional information on the licensee's evaluation and compliance with GDC-60 with regard to means to control the release of radioactive effluents is provided in Section 2.5.6 of this SE.

License Renewal impact for the CRVS is discussed in Section 2.7.1 of this SE.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS (or CRVS at PTN) 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 changes to parameters affecting environmental conditions for control room personnel and equipment so that the requirements of GDC-4 are met. The NRC staff concludes that the CRVS will continue to provide the required protection following implementation of the proposed EPU to meet the requirements of GDC-19. The NRC staff further concludes that the CRVS will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the CRVS will continue to meet the requirements of GDCs 4, 19, and 60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CRVS.

2.7.4 Spent Fuel Pool Area Ventilation System

Regulatory Evaluation

The function of the spent fuel pool area ventilation system (SFPAVS) is to maintain ventilation in the spent fuel pool equipment areas, permit personnel access, and control airborne radioactivity in the area during normal operation, AOOs, and following postulated fuel handling accidents. 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 Standard Review Plan, Section 9.4.2.

NRC Technical Evaluation

The licensee states that the SFPAVS at PTN Units 3 and 4 have no safety-related portions and that the systems are not credited for either iodine removal or for isolation of release paths. At PTN Unit 3, the discharge from spent fuel pool pit area ventilation subsystem (SFPPAVS) is directed through HEPA filters to its own vent. At PTN Unit 4 the SFPPAVS is part of the auxiliary building ventilation system and its discharge is also directed through HEPA filters to the plant stack. Radiation monitoring is provided through these discharge paths. At Unit 3, an operator action from the control room is initiated when the exhaust monitor annunciates an alarm in the control room. There is no similar control function on Unit 4 SFPPAV, as all such controls are part of plant stack effluent monitoring. The licensee states that the decay heat in the spent fuel pool will increase under EPU conditions. However, the spent fuel pool cooling system will be modified as part of the EPU, such that the pool water temperature will remain below the current licensing basis during normal and refueling operations, and any other scenarios that were presently evaluated at PTN. This is discussed in Section 2.5.4, "Spent Fuel Pool Cooling and Cleanup System," of this SE. The licensee states that with the exception of one area, there are no additional heat sources introduced by the EPU in the spent fuel pool building, and therefore, the building ambient design temperatures as in the current licensing basis are not affected by EPU. The one area that may experience higher heat loads is spent fuel pool equipment area served by the spent fuel pool equipment room ventilation subsystem (SFPERVS). The license stated that this area may experience higher heat loads for limited periods during the conclusion of refueling outages and post-refueling startup. The licensee stated that any required improvements to the SFPERVS will be determined and implemented as part of the SFP cooling system upgrade. Based on the information presented by the licensee, the NRC staff concludes that the SFP area ventilation systems are either adequate or will be upgraded if needed, to maintain the required temperature conditions for personnel and equipment during EPU operation. The NRC staff's discussion on radiological consequences of fuel handling accidents is provided in Section 2.9.2 and discussion on airborne radioactivity released from the spent fuel in the pool which is collected by the system and discharged to the atmosphere via the fuel handling building vent stack is provided in Section 2.10.1.

The licensee stated that the SFPAVS is determined not to be within the scope of license renewal and there are no changes to this determination as a result of the EPU.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the spent fuel area ventilation systems. 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 spent fuel pool and associated equipment areas, permit personnel access, control airborne radioactivity in the area, control release of gaseous radioactive effluents to the environment, and provide appropriate confinement. Based on this, the NRC staff concludes that the spent fuel area ventilation systems will continue to meet the requirements of GDC 60 and GDC 61.

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

Regulatory Evaluation

The function of the auxiliary and radwaste area ventilation system and the turbine area ventilation system is to maintain ventilation in the respective areas served by the system, permit personnel access, and control the concentration of airborne radioactive material in these areas during normal operation, during anticipated operational occurrences (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 these systems 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 Standard Review Plan, Sections 9.4.3 and 9.4.4.

NRC Technical Evaluation

The auxiliary building ventilation system provides clean air to the operating areas of the building and exhausts air from the building through a bank of HEPA filters to the plant stack. Radiation monitoring is provided for this exhaust path. The electrical equipment rooms in the building are provided with both nonsafety-related and safety related air conditioning systems. The safety related system is provided to prevent room temperature from exceeding 104 °F for the safety related equipment located in these rooms. The safety related system is also provided with redundancy and can be powered from the emergency diesel generators.

The radwaste building ventilation HVAC system provides cooling and ventilation for operating personnel and equipment in the radwaste facility. The system consists of a combination of ventilation systems to the general areas and nonsafety-related air conditioning systems to the control and electrical switchgear rooms during normal operation. The exhaust fans in the facility discharge to the atmosphere via the auxiliary building ventilation system.

Due to the open design of PTN's secondary, the turbine area ventilation system is comprised primarily of the load center and switchgear room air conditioning system. The system is provided with redundancy and is designed to maintain the temperature in the rooms within the limits of the equipment located in the rooms, during normal and emergency conditions.

The licensee stated that the effluent release paths from these systems to the environment are monitored and the current radiological control functions are unaffected by the EPU and will

continue to be maintained. Progression of air flow through compartments of ever-increasing airborne radioactive potential will also be maintained in the post-EPU plant configuration. The licensee further stated that the increase in LOCA heat loads as a result of the EPU are minimal, and therefore, the EPU LOCA temperatures in rooms containing safety related electrical equipment will not be impacted by the EPU.

The staff did not identify any modifications or additions to the auxiliary building ventilation system components, as the result of EPU, which would introduce any new functions or change the functions of existing components that would affect the license renewal system evaluation boundaries. In addition, operation of the auxiliary building ventilation system at EPU conditions does not add any new types of materials or previously unevaluated materials to the system.

The licensee evaluated the ventilation systems in this section 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 aging management programs. The licensee states that the EPU does not add new or previously unevaluated effects that necessitate a change in aging management programs or require a new program that would affect the system boundaries for license renewal. Based on the information provided by the licensee, the NRC staff concludes that the proposed EPU will have no impact on the auxiliary and radwaste area and turbine area ventilation systems.

Conclusion

The NRC staff has reviewed the effects of the proposed EPU on the auxiliary and radwaste area and turbine areas 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 maintain ventilation in the auxiliary and radwaste equipment areas and in the turbine area, permit personnel access and 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 auxiliary and radwaste area and turbine areas ventilation systems will continue to meet their current licensing basis with respect to the requirements of GDC-60.

2.7.6 Engineered Safety Feature 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 Standard Review Plan, Section 9.4.5.

NRC Technical Evaluation

There are several engineered safety feature ventilation systems at PTN Units 3 and 4. The NRC staff's review of some of these systems for post-EPU operation is provided in other sections of this safety evaluation. The NRC staff's review of electrical equipment room (EER) HVAC system in the auxiliary building and load center and switchgear room air conditioning system (LC&SR VAC) in the turbine building is provided in Section 2.7.5. The NRC staff's review of the control room ventilation system is provided in Section 2.7.3. The NRC staff's review of the emergency containment coolers is provided in Sections 2.6.4 and 2.6.5.

The licensee stated that EPU will not increase the rated loads of the emergency diesel generators (EDG). There are no modifications planned to the EDG structures as a result of the EPU and engine coolant temperature setpoint will remain unchanged. Based on this information, the NRC staff concludes that the EDG Building Ventilation System will not be adversely impacted by the proposed EPU.

The control building also contains ESF ventilation and cooling systems serving the dc equipment/inverter room (DCEIR VAC) and the computer/cable spreading room (CF&CSR A/C). The licensee stated that the batteries in the battery rooms served by the DCEIR VAC are not changing in any way by the EPU, and therefore, the hydrogen loading on this system is not impacted. The licensee further stated that the EPU will cause a slight increase in heat loads from some cables due to amperage increases; however, the increase is so small that it will not impact the ability of the DCEIR VAC and CF&CSR A/C to maintain the room temperatures within design.

The licensee states that the changes in heat loads in the cited areas were found to be negligible; therefore no change in the ventilation subsystems is necessary. The licensee evaluated the systems under EPU conditions and ensured its capability of circulating sufficient air for preventing accumulation of flammable or explosive gases, and also its ability to control airborne particulate material accumulation. The licensee states that the evaluation of the plant equipment changes for the EPU conditions did not require modification of these systems, and no plant equipment changes are required that could create a new potentially unmonitored radioactive release path. The NRC staff concurs that that an insignificant increase in the heat load will not impact the ventilation equipment and the capability to control and minimize the release of airborne particles to the environment will be maintained.

The licensee evaluated the ESFVS 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 aging management programs. The licensee states that the subject systems are not being modified as a result of the EPU, therefore, the existing age management schedules that are in place will remain unaffected by EPU. Based on the information provided by the licensee, the NRC staff concludes that the EPU will have no impact on license renewal.

Conclusion

The NRC staff 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 GDCs 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 is based on (1) GDC-4, insofar as it requires that safety-related structures, systems, and components 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-17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of 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 containing radioactivity be designed with appropriate confinement and containment.

NRC Technical Evaluation

The containment ventilation systems consists of four systems: (1) emergency containment coolers (ECCs), (2) normal containment cooling (NCC) system, (3) control rod drive mechanism cooling (CRDMC) system and (4) containment purge system. The staff's review of the ECCs is provided in Sections 2.6.4 and 2.6.5.

The normal containment cooling system is designed to maintain the temperature in containment at or below a normal ambient of 120 °F and to provide air mixing and circulation in containment to permit maintenance and/or refueling operations. The NCC system consists of four fan-coil units with a common discharge header, with three units capable of providing sufficient cooling during normal operations. The licensee stated that heat loads in containment will go up as a result of the EPU. The licensee stated that all the coolers will be replaced with new units prior to the implementation of the EPU and they will be of sufficient capacity to accommodate the increased heat loads in containment. The NCC system is not credited during accident

conditions, however, a current feature to be able to manually load the system on EDG power will be retained during post-EPU conditions.

As described in Section 2.7.7 of the LR, the CRDMC system supplements the normal containment cooling system and can be used to remove heat from the reactor vessel head during natural circulation cool-down initiated by a loss of offsite power. The CRDMC system is not credited during accident conditions, however, a current feature to be able to manually load the system on EDG power will be retained during post-EPU conditions. There are two CRDM cooling units per plant. The CRDM cooling systems at PTN Units 3 and 4 were recently modified as part of the reactor head replacement projects. The CRDMC system is designed to maintain the CRDM electro-magnetic coils at a temperature below 392 °F with one or both fans operating. Under the current conditions, the exit air temperature prior to entering the cooling units is limited to a temperature below 170 °F. A computational fluid dynamics analysis was performed to verify that the modified system provides sufficient cooling to the electro-magnetic coils. The analysis is based on conservatively high inlet air temperature (i.e. containment temperature) of 125 °F. The analysis determined that the CRDM electro-magnetic coil temperature and the exit air temperature limitations will be met. A similar analysis was performed for EPU conditions. The analysis determined that there would be an increase in the CRDM electro-magnetic coils temperature, but it still remains below the limit of 392 °F. The analysis also determined that the exit air temperature will exceed 170 °F. The licensee increased the limit on the exit air temperature to 180 °F. The higher temperature resulted in a need to modify the motor component of the CRDM cooling unit. The modified unit will allow single fan operation thus maintaining the current reliability of the CRDM cooling system by qualifying the redundancy of the fans. The estimated increase in containment heat load from the CRDM cooling system as a result of the proposed EPU was evaluated as part of the normal containment cooling system.

The containment purge system is designed for purging gases and to reduce the level of radioactive contamination in the containment atmosphere to allow unlimited personnel access to the containment during plant shutdowns. The system consists of two supply fans and associated ductwork to supply outside air into the containment and two exhaust fans to exhaust containment air through roughing filters into the plant stack. The system is equipped with inline and area radiation monitors for use during the purging operations. The system is not credited for operating under accident conditions, however, the system supply and exhaust lines are equipped with containment isolation valves, designed to perform a containment isolation function. There are no changes required to the equipment, control logic or operation of the containment purge system as a result of the EPU.

The licensee addressed the impact of the EPU on license renewal as it relates to systems contained in this section. There is no impact on the ECCs as noted in the NRC staff's evaluation under Section 2.6.5. The licensee stated that the modification packages implementing the replacement of the NCC system will address the EPU impact on the license renewal. The impact of design temperature change on the CRDMC system is evaluated in Section 2.8.4.1. The containment purge system is unaffected by the EPU.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the containment ventilation systems with respect to heat removal and radioactivity removal from the containment atmosphere. 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 GDCs 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

The current fuel system is a design of 15x15 seven-grid debris resistant fuel assembly (DRFA) in Turkey Point Nuclear Plant (PTN) Units 3 and 4. In order to implement the extended power uprate (EPU), the licensee will transition from the current 15x15 DRFA design to the 15X15 seven-grid upgrade fuel assembly design one cycle prior to the EPU. The upgrade fuel design consists of many new features including integral fuel burnable absorber, I-spring structural mid-grids, intermediate flow mixing (IFM) grids, Alloy 718 protective gird (P-grid) in the bottom grid, debris filter bottom nozzle (DFBN), etc. During the fuel transition, there is a concern of mixed cores of upgrade and DRFA fuel assemblies because of the different fuel design characteristics. The licensee indicated that the EPU was analyzed from mixed cores to the full cores of upgrade fuel assemblies.

Based on the requirement of Section 4.2 of NRC's NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (SRP or Standard Review Plan), the licensee analyzed the upgrade fuel assembly thermal-mechanical design for EPU conditions. The analysis includes fuel rod internal pressure, cladding corrosion, fuel melting, seismic, and loss-of-coolant accident (LOCA) loading, etc. The licensee intends to demonstrate that the upgrade fuel assembly design performs adequately under EPU conditions.

Protective Grid

A recent industry issue associated with the protective grid (P-grid) design has been identified involving grid dimple separation. The P-grid issue resulted in some fuel failures due to the debris fretting wear of the loose fragments from the grid dimple separation. The cause of the grid dimple separation was mainly due to primary water stress corrosion cracking (PWSCC). To date the known fuel failure due to the P-grid issue has been limited to the 17x17 fuel design. There has been no evidence of dimple separation of the P-grid for the 15x15 fuel design employed at the PTN Units 3 and 4.

An intermediate compensatory measure (ICM) was developed by Westinghouse to help mitigate dimple detachment using a pinning process during the heat treatment of the P-grid in the manufacturing process. The pinned P-grid is being used in the PTN units per ICM recommendation until the new 15x15 robust protective grid (RPG) is implemented. In addition, the upgrade fuel design has a coating of zirconium dioxide (ZrO_2) on the lower portions of the cladding to increase debris fretting resistance. The combination of the ICM pinning process and

ZrO_2 coating has shown significant reduction in the risk of fuel failure due to the P-grid corrosion cracking issue.

Based on the measure of ICM pinning process and ZrO_2 coating, the NRC staff concludes that the licensee implementation is adequate in addressing the P-grid corrosion cracking issue for PTN Units 3 and 4 at EPU.

Rod Internal Pressure

SRP Section 4.2 states that fuel rod internal gas pressure should remain below the nominal system pressure during normal operation or other limits must be justified. The licensee analyzed the fuel rod internal pressure using the approved methodology including the PAD code at EPU limiting conditions. The licensee determined that the maximum calculated rod pressure remained below the reactor coolant system pressure for the EPU.

Based on the approved methodology, the NRC staff concludes that the rod pressure analysis is acceptable for PTN Units 3 and 4 at EPU.

Cladding Corrosion and Hydrogen Pickup

The licensee analyzed the fuel rod corrosion for steady-state and transient EPU conditions using the approved methodology including the PAD code. The results showed that the maximum calculated clad metal-to-oxide interface temperatures were below the design limits for steady-state and transient EPU conditions. The results also indicated that the hydrogen pickup did not exceed the design limit at the end of life. The licensee determined that cladding corrosion and hydrogen pickup would have no adverse effects during EPU.

Based on the approved methodology, the NRC staff concludes that the cladding corrosion and hydrogen pickup analyses are acceptable for PTN Units 3 and 4 at EPU.

Fuel Melting

The melting temperature for uranium oxide (UO_2) in the unirradiated condition is 5080 °F and decreases 58 °F per 10,000 megawatts-day per metric tons of uranium (MWD/MTU) fuel burnup. The licensee has a fuel centerline temperature design limit, which is significantly below the fuel melting temperature, to preclude fuel melt for the EPU limiting conditions. The licensee's analysis using the approved methodology including the PAD code showed that the power required to reach this fuel centerline temperature design limit was [[ ]] kW/ft for the upgrade fuel design. However, the maximum calculated local linear power for EPU conditions was below the [[ ]] kW/ft design limit, which indicated that the fuel melting criterion and analysis were conservative for the upgrade fuel design.

Based on the approved methodology, the staff concludes that the fuel melting analysis is acceptable for PTN Units 3 and 4 at EPU.

Seismic and LOCA Loading

Earthquakes and postulated pipe breaks in the reactor coolant system would result in external forces on fuel assemblies. SRP Section 4.2 states that fuel system coolability should be maintained and that damage should not be so severe as to prevent control rod insertion when required during these low probability accidents. Appendix A to SRP 4.2 describes the review that should be performed of the fuel assembly structural response to seismic and LOCA loads. The seismic and LOCA loads should be combined according to the square-root-of-sum-of-squares (SRSS) method.

The licensee evaluated seismic and LOCA loading using the approved methodology described in WCAP-9401-P-A[81] for mixed core of DRFA and upgrade fuel designs, and a full core of the upgrade fuel design at the EPU conditions. By letter dated May 18, 2011, the licensee provided initial responses to the NRC staff RAI. The core plate motions and vertical impacts on the nozzles were used in the seismic and LOCA analyses for the EPU conditions. The licensee applied several limiting fuel loading configurations for the mixed core. The largest branch line breaks, either the accumulator line (ACC) break, surge line break, or RHR line break, were considered when generating LOCA hydraulic forcing functions used as input to the analysis. Subsequently, the licensee revised the analysis due to updated core plate motions to account for the change in reactor vessel stiffness values. The revised analysis resulted in updating the licensing report Sections 2.8.1.2.3.1 and 2.8.1.2.3.5.

The revised analysis examined a homogeneous core of 15x15 upgrade fuel assemblies, and mixed cores of 15x15 DRFA and upgrade fuel assemblies. The allowable grid strengths were established at a 95% confidence level on the true mean from the distribution of grid crush data at operating temperatures. The licensee also took into account of the grid elevation offset between the upgrade and DRFA fuel assemblies. For the limiting condition in the seismic and LOCA analyses from a magnitude and orientation standpoint, the licensee determined that the core plate motion based on the ACC break produced the highest hydraulic forcing function for the structural evaluation.

Using the SRSS method combining the seismic and LOCA forces, the results showed that the maximum impact force on fuel assemblies of homogeneous and mixed cores were below the allowable grid crush limit except for the peripheral assemblies in the three-fuel-assembly and seven-fuel-assembly rows. Depending on the core loading pattern, certain locations in the seven-fuel-assembly rows could have crushed fuel assemblies with rod control cluster assemblies (RCCAs). For the most limiting case of ACC break, the licensee determined that the RCCA core locations of F2 and F14 could have crushed assemblies after examining several loading patterns. To ensure grid crush in RCCA locations does not occur, the licensee requires that a limit be maintained in the reload safety analysis checklist (RSAC) during the only transition cycle of mixed core of DRFA and upgrade fuel assemblies. The RSAC requires that only DRFA fuel assemblies be loaded in core locations E2 and E14 when DRFA fuel assemblies are loaded in RCCA core locations F2 and F14.

In addition, the analysis showed that the maximum combined impact forces on the mid grids and IFM grids were below the grid crush limits except for the three fuel assembly rows on the core periphery, which were non-RCCA locations. The impact forces of these three fuel

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[81] WCAP-9401-P-A, David, S. L., et al, “Verification and Testing Analysis of the 17x17 Optimized Fuel Assembly,” August 1981.

assembly rows exceeded the grid crush limits of DRFA and upgrade fuel. As stated in the SRP, it is permissible to exceed the grid crush limits provided that it can be demonstrated that RCCA insertability and a coolable geometry are maintained. The three fuel assembly row locations did not have RCCA so that the insertability was not a concern. Based on the fact that these peripheral assemblies were in very low power locations, the licensee determined that the PCT penalty was not required for these assemblies and the coolable geometry was maintained. The licensee also determined that long term core cooling was ensured as the decay heat in these peripheral locations were relatively low compared to the in-board assemblies. The stress analysis results showed that adequate margin for both fuel rods and thimble tubes existed. Thus fragmentation of fuel rods and thimbles tubes would not occur. The NRC staff reviewed the analysis, and determined that the results are acceptable based on a conservative approach.

Based on the approved methodology and conservative approach including the RSAC limitation, the NRC staff concludes that the seismic and LOCA loading analyses are acceptable for Turkey Point Units 3 and 4 at EPU.

PAD 4.0 CORRECTIONS

By letter dated December 31, 2011 (L-2011-561), [82] in response to an RAI regarding fuel thermal conductivity degradation, FPL performed various assessments and calculations to address the impact of thermal conductivity degradation (TCD) on their EPU safety analyses. This section describes the NRC staff's review of the TCD evaluation on fuel rod thermal-mechanical design and LOCA stored energy.

<u>PAD4TCD</u>

The currently approved Westinghouse PAD 4.0 fuel rod performance code does not account for TCD with exposure. Westinghouse is currently working on a formal revision to the PAD code. As an interim solution, FPL proposes to replace PAD 4.0 with a modified version that properly accounts for TCD. The revised fuel performance code, PAD4TCD, will be utilized to perform fuel thermal-mechanical design analyses and generate input to downstream safety analyses. FPL has provided a commitment, which the NRC staff is issuing as a license condition to implement the formal revision to PAD once it becomes available. Recognizing the immediate need to address TCD in support of the EPU application, the NRC staff accepts the proposed interim solution for Turkey Point Units 3 and 4.

By letter dated December 31, 2011, FPL stated that the form of the equations and coefficients used to model the exposure dependence within PAD4TCD's fuel thermal conductivity model are identical to those in the NRC approved STAV7.2 fuel performance code.[83] During a January 2012 audit, the NRC staff questioned the coefficients within the PAD4TCD thermal conductivity model and differences relative to STAV7.2. In a letter dated February 2, 2012, Westinghouse provided the coefficients within the PAD4TCD model. Note that these coefficients are based on an unapproved version of STAV, referred to as STAV7.3.

[82] ML12009A113
[83] WCAP-15836-P-A, Supplement 1, April 2006

As described in RAI response (L-2011-561), PAD4TCD fuel centerline predictions were compared against Halden high burnup fuel temperature measurements including Instrumented Fuel Assembly (IFA)-[[ ]]. Figure 3-1 of L-2011-561 illustrates the improved accuracy of PAD4TCD compared against the original PAD 4.0 code predictions relative to [[ ]] measured fuel temperature. NUREG/CR-7002, Volume 2 documents the integral assessment of the FRAPCON-3.4 code including comparisons to the Halden fuel temperature database. The FRAPCON-3.4 and PAD4TCD validation included many of the same high burnup test rods.

Figure 2.8.1-1 illustrates the burnup and temperature dependence of the PAD4TCD thermal conductivity model. The enhanced exposure dependence is evident in this figure. Figures 2.8.1-1 through 2.8.1-5 provide a comparison of PAD4TCD and FRAPCON-3.4 thermal conductivity as a function of temperature at several exposure levels. Examination of these plots reveals good agreement between the two models.

Based upon (1) comparison of the PAD4TCD model predictions against Halden high burnup fuel temperature measurements and (2) good agreement of the temperature dependent and exposure dependent coefficients between PAD4TCD and FRAPCON-3.4 thermal conductivity models, the NRC staff finds the PAD4TCD thermal conductivity model acceptable.

The revised PAD4TCD thermal conductivity and its associated higher fuel temperature predictions have a significant impact on predicted fission gas release. As described in the RAI response (L-2011-561), the approved PAD 4.0 fission gas release model [[ ]]. In other words, the PAD 4.0 fission gas release model [[ ]]. To avoid an overly conservative calculation with PAD4TCD, Westinghouse proposes to [[ ]] match the PAD 4.0 predictions. On the surface, this approach seems reasonable. As described below, the NRC staff performed independent FRAPCON-3.4 calculations to evaluate PAD4TCD fuel temperature and fission gas release predictions.

The ability of a fuel performance code to accurately predict fuel temperature has an impact on the calibration and validation of the PAD code. With the exception of the fission gas release model, the remaining PAD4TCD models were not adjusted to account for the revised thermal conductivity model and its associated higher fuel temperature predictions. This potential de-calibration may impact the code's best-estimate predictions and the previously quantified modeling uncertainties. To assess this potential issue, the NRC staff performed independent FRAPCON-3.4 design calculations.

To support the NRC staff's calculations, Westinghouse provided a UO2 fuel rod and Integral Fuel Burnable Absorber (IFBA) fuel rod FRAPCON input deck containing [[ ]], a comparison of predicted results, and manufacturing tolerances on selected design parameters. By letters dated January 17, 2012, and January 23, 2012, this information was provided in Reference (LTR-NRC-12-2, Revision 1) and (LTR-NRC-12-4).

Rod Internal Pressure Design Calculation

Table 1 and Table 2 of Reference (LTR-NRC-12-2, Revision 1) lists a comparison of calculated void volume, fission gas release, and rod internal pressure from benchmark FRAPCON-3.4, PAD 4.0, and PAD4TCD cases for the limiting UO_2 and IFBA fuel rods. Examination of these tables reveals the following:

- [[ ]]
- [[ ]]
- [[ ]]
- [[ ]]

The publically released version of FRAPCON-3.4 contains a code error. Specifically, if the ZrB2 option is turned on, then the code over-writes the input fuel pellet density with the input ZrB2 coating density. Correcting for this error, the staff ran FRAPCON-3.4 with the IFBA input deck and obtained the results listed in Table 2.8.1-1. These new results replace the values in Table 2 of Reference LTR-NRC-12-2, Revision 1.

Table 2.8.1-1: Comparison of PAD 4.0, PAD4TCD, and FRAPCON-3.4
Results for the Limiting IFBA Fuel Rod

Parameter	FRAPCON-3.4	PAD 4.0	PAD4TCD
BOL Cold VV (in3)	1.982	[[ ]]	[[ ]]
EOL Hot VV (in3)	1.3938	[[ ]]	[[ ]]
EOL FGR (%)	14.35	[[ ]]	[[ ]]
EOL RIP (psi)	1803	[[ ]]	[[ ]]

As described in Reference LTR-NRC-12-2, Revision 1, differences in algorithms and capabilities make it difficult to duplicate results between PAD4TCD and FRAPCON-3.4. In addition to the ability to [[ ]], the number of axial power shapes allowed in FRAPCON-3.4 is limited relative to PAD. In Reference LTR-NRC-12-4, Westinghouse quantified the impact of employing the limited, generic axial power shapes relative to the EPU design calculation. As listed in Table 1 of LTR-NRC-12-4, the PAD4TCD best-estimate EOL rod internal pressure [[ ]] psi to [[ ]] psi and the upper bound fission gas release uncertainty case [[ ]] psi to [[ ]] psi.

Code-to-code comparisons will always yield differences, even if identical design and operating parameters are used. The above benchmark demonstrates that the PAD4TCD code provides, as expected, an improvement in the rod internal pressure calculation. Furthermore, the PAD4TCD predicted best-estimate EOL rod internal pressure is conservative relative to the FRAPCON-3.4 best-estimate value.

A better approach than best-estimate code-to-code benchmarks is to compare the PAD4TCD design methodology, including its combination of uncertainties, against FRAPCON-3.4 with its application methodology. For this exercise, each code will be used within its unique capabilities and specific modeling uncertainties.

The PAD 4.0 methodology produces an upper tolerance rod internal pressure calculation by statistically combining [[ ]]. The uncertainty on [[ ]] dominates this square-root-sum-of-the-squares (SRSS) calculation. For the Turkey Point EPU analysis, the predicted upper tolerance rod internal pressure for the limiting IFBA fuel rod [[ ]] to [[ ]] psia when calculated with the PAD4TCD code. As expected, the inclusion of TCD produces a higher rod internal pressure.

The NRC has developed a statistical package for FRAPCON-3.4 to perform benchmark design calculations. The statistical package randomly samples among specified distributions of manufacturing tolerances and modeling uncertainties to create multiple input decks, executes each of these unique cases, and compiles the results. For this benchmark, the NRC staff ran 150 cases, sampling among the distribution of manufacturing tolerances for cladding ID, cladding outer diameter (OD), pellet OD, pellet density, plenum length, and backfill pressure provided in Table 3 of Reference LTR-NRC-12-2, Revision 1. The FRAPCON-3.4 fission gas release modeling uncertainty used in these calculations is documented in NUREG/CR-7022, Volume 2. A 95/95 upper tolerance limit (UTL) is calculated from the distribution of resulting rod internal pressures.

Table 2.8.1-2 compares rod internal pressure design calculation results from FRAPCON-3.4 and PAD4TCD for the limiting EPU IFBA fuel rod. Examination of Table 2.8.1-2 reveals that the predicted upper tolerance rod internal pressure, while calculated using different codes and methods, [[ ]].

Table 2.8.1-2: Comparison of PAD4TCD and FRAPCON-3.4 Rod Internal Pressure Design Calculations for the Limiting IFBA Fuel Rod

Case	Nominal (psi)	Upper Tolerance (psi)
PAD4TCD	[[ ]]	[[ ]]
FRAPCON	1803	- -
FRAPCON+Tol	- -	1948
FRAPCON+Tol+FGR	- -	2323

Notes:

1. Tol = random sampling of manufacturing tolerances (e.g., plenum length, pellet OD).
2. FGR = random sampling of FGR model uncertainty.

Rod internal pressure design calculations were also performed with the limiting UO2 fuel rod input deck provided in Reference LTR-NRC-12-2, Revision 1. These FRAPCON calculations produced a mean rod internal pressure of 1648 psi and 95/95 UTL of 1793 psi (including tolerances) and 2134 psi (including tolerances and FGR model uncertainty). The IFBA fuel rod remained more limiting than the UO2 fuel rod.

<u>Cladding Strain Design Calculation</u>

The revised PAD4TCD thermal conductivity and its associated higher fuel temperature predictions will have an impact on predicted cladding strain during an anticipated operational occurrence (AOO) overpower scenario. A change in fuel thermal conductivity will affect the initial pellet outer diameter (OD), which in turn affects the pellet-to-cladding gap size and the allowable pellet expansion prior to loading the cladding, and the amount of pellet thermal expansion.

The AOO overpower cladding strain cases were repeated with PAD4TCD. As expected, the predicted cladding strain [[ ]]. For one particular case, the predicted cladding strain [[ ]]% to [[ ]]%. All of the cases continue to satisfy the Westinghouse cladding strain SAFDL, less than 1.0% total (elastic+plastic).

AREVA's RODEX2 fuel performance code also lacks an exposure dependent fuel thermal conductivity model. Independent from Westinghouse, AREVA developed a method for assessing the impact of TCD on predicted AOO cladding strain. In August 2011, the NRC staff audited the augmentation factors developed by AREVA to compensate for TCD (Audit Report, ML11245A196). While the code algorithms and methods are different, the estimated impact of TCD (Δstrain) is similar.

The NRC staff performed an AOO overpower cladding strain design calculation using the FRAPCON-3.4 statistical package. In Reference NRC-LTR-12-2, Revision 1, Westinghouse provided the [[ ]] for the limiting cladding strain design calculation. Starting with the limiting UO_2 fuel rod FRAPCON input deck (from the peak pressure analysis); an AOO power ramp of an equivalent magnitude (ΔKW/ft) was modeled at approximately the same exposure as the Westinghouse design calculation. For this benchmark, the NRC staff ran 150 cases, sampling among the distribution of manufacturing tolerances for cladding inner diameter (ID), cladding OD, pellet OD, pellet density, plenum length, and backfill pressure provided in Table 3 of Reference LTR-NRC-12-2, Revision 1. The FRAPCON-3.4 pellet thermal expansion modeling uncertainty used in these calculations is documented in NUREG/CR-7022, Volume 2. A 95/95 upper tolerance limit (UTL) is calculated from the distribution of resulting cladding strains.

The FRAPCON-3.4 cladding strain design calculation resulted in a mean cladding strain of 0.846% and 95/95 UTL of 0.994%. Differences in predicted strain are likely due to different

initial conditions within the fuel rod at the time of the AOO power ramp. The FRAPCON-3.4 benchmark simply imposed a power ramp (of equivalent ΔKW/ft) on the limiting peak pressure fuel rod. As a result, the peak local power was significantly higher even though the change in local power was maintained. While this approach is not ideal, it still demonstrates that the predicted cladding strain at a 95/95/UTL remains below the design limit.

Power-to-Melt Design Calculation

The revised PAD4TCD thermal conductivity and its associated higher fuel temperature predictions will have an impact on predicted power-to-melt limits. In the Westinghouse methodology, PAD 4.0 is used to back-calculate the peak local power which yields a fuel centerline temperature at the point of melting. In general, the UO_2 melting point equals 5080°F – 58°F per 10 GWd/MTU. These power-to-melt limits are then compared to predicted local power peaking during various AOOs and accidents to assess whether fuel melting has occurred.

Since both thermal conductivity and fuel melting temperature decrease with exposure, the power-to-melt limits are a strong function of burnup. Table 5-1 of Reference L-2011-561 lists the PAD4TCD calculated power-to-melt limits which drop from a peak of [[ ]] KW/ft near beginning-of-life to [[ ]] KW/ft at end-of-life. The current PAD 4.0 power-to-melt limit, which includes an exposure dependence on melting temperature but lacks one on thermal conductivity, is [[ ]] KW/ft. As expected, the application of PAD4TCD results in significant reductions in power-to-melt limits, especially at higher exposure.

AREVA's RODEX2 fuel performance code also lacks an exposure dependent fuel thermal conductivity model. Independent from Westinghouse, AREVA developed a method for assessing the impact of TCD on predicted power-to-melt limits. In August 2011, the NRC staff audited the augmentation factors developed by AREVA to compensate for TCD (Audit Report, ML11245A196). While the code algorithms and methods are different, the estimated impact of TCD (ΔKW/ft) is similar.

Utilizing FRAPCON-3.4, the staff performed power-to-melt calculations at several exposure points. These cases were run with the limiting UO_2 fuel rod FRAPCON input deck (from the peak pressure analysis). Figure 2.8.1-6 provides a comparison of the power-to-melt limits calculated using PAD4TCD and FRAPCON-3.4. Examination of this figure reveals a reasonable agreement between the two codes. Both calculations capture the strong exposure dependence expected in power-to-melt limits.

Based upon (1) comparison of the PAD4TCD model predictions against Halden high burnup fuel temperature measurements, (2) comparison of PAD4TCD and FRAPCON-3.4 thermal conductivity models, and (3) comparison of PAD4TCD design calculations against benchmark FRAPCON-3.4 design calculations, the NRC staff finds the PAD4TCD fuel performance code model acceptable.

Impact of TCD on Fuel Thermal-Mechanical Design

Section 5 of Reference L-2001-561 describes the impact of TCD on the EPU fuel thermal-mechanical design analyses. As an interim solution, FPL is implementing the revised code

PAD4TCD to perform fuel thermal-mechanical design analyses and generate input to downstream safety analyses. As described above, the staff finds the PAD4TCD code acceptable. Its prediction of fuel temperature and stored energy as a function of exposure has been found acceptable by comparison with FRAPCON and direct comparison with data. All of the fuel rod design criteria continue to be satisfied.

Figure 2.8.1-1: PAD4TCD UO2 Thermal Conductivity as a function of Burnup and Temperature

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Figure 2.8.1-2: Comparison of PAD4TCD and FRAPCON-3.4 Thermal Conductivity at 0 GWd/MTU against Institute for Transuranium Elements (Ronchi et al.) data

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Figure 2.8.1-3: Comparison of PAD4TCD and FRAPCON-3.4 Thermal Conductivity at 20 GWd/MTU

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Figure 2.8.1-4: Comparison of PAD4TCD and FRAPCON-3.4 Thermal Conductivity at 40 GWd/MTU

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Figure 2.8.1-5: Comparison of PAD4TCD and FRAPCON-3.4 Thermal Conductivity at 60 GWd/MTU

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Figure 2.8.1-6: Comparison of PAD4TCD and FRAPCON-3.4 Predicted Power-to-Melt Limits

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Conclusion

The NRC staff has reviewed the licensee's upgrade fuel thermal-mechanical design for PTN Units 3 and 4 at EPU in the submitted licensing report. Based on the evaluation, the staff concludes that the upgrade fuel thermal-mechanical design is acceptable to a peak rod average burnup limit of 62 GWD/MTU for PTN Units 3 and 4 at EPU.

2.8.2 Nuclear Design

Regulatory Evaluation

The Nuclear Regulatory Commission (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 reactor coolant pressure boundary (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 the following general design criteria (GDC) from Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants": (1) 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; (2) GDC-11, insofar as it requires that the reactor core be designed so that the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity; (3) GDC-12, insofar as it requires that the reactor core be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can be reliably and readily detected and suppressed; (4) GDC-13, insofar as it requires that instrumentation and controls be provided to monitor variables and systems affecting the fission process over anticipated ranges for normal operation, AOOs and accident conditions, and to maintain the variables and systems within prescribed operating ranges; (5) GDC-20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to automatically initiate operation of systems and components important to safety under accident conditions; (6) GDC-25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (7) GDC-26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (8) GDC-27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (9) GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the

core. Specific review criteria are contained in NRC's NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (Standard Review Plan or SRP), Section 4.3, and other guidance provided in Matrix 8 of RS-001, "Review Standard for Extended Power Uprates," December 2003.

NRC Technical Evaluation

In conjunction with its application for an extended power uprate (EPU), the licensee has proposed to load into the reactor core a new type of fuel assembly with an increased enrichment limit for the fissile isotope uranium-235. The EPU and fuel system change can affect key nuclear safety parameters, such as the core power distribution, reactivity coefficients, reactivity control requirements and provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation. Many of these parameters are inputs to the accident analyses, as discussed in the licensee's application, Chapter 14 of the Turkey Point Nuclear Plant (PTN) UFSAR, and Section 2.8.5 of this safety evaluation.

The NRC staff's review of the licensee's intended changes to the nuclear design focused on the conformance of the proposed EPU configuration with the nine GDCs enumerated above.
As described in the licensee's application, PTN was licensed, not to the GDCs currently existent in Appendix A to 10 CFR 50, but to plant-specific design criteria derived from proposed GDCs issued by the Atomic Energy Commission in 1967. Based on the licensee's discussion of its current licensing basis requirements, the staff's review considered the intent of the plant-specific design criteria to which PTN was licensed to be consistent with the GDCs identified above that are associated with nuclear design, with the exception that no plant-specific criterion exists corresponding to GDC-11. Based upon the information presented regarding the nuclear design, the staff agreed with the licensee's conclusion that negative reactivity feedback is accommodated by the nuclear design, based on (1) the fact that the upper limit for the reactivity feedback parameters would not be changed as a result of the EPU, (2) the NRC staff's approval of the licensee's existing technical specifications governing the most positive moderator temperature coefficient,[84] and (3) the existence of a negative Doppler coefficient. Ultimately, however, to ensure that GDCs associated with nuclear design are satisfied, confirmation of acceptability is also necessary from the NRC staff's review of the licensee's safety analyses for the proposed EPU condition, which is addressed in Section 2.8.5 of this evaluation.

The licensee stated that no changes to the nuclear design philosophy or methods have been implemented because of the EPU. The licensee further stated that standard analytical models and methods are applied in the nuclear design analysis for EPU cores, models and methods which have been demonstrated to accurately describe the neutronic behavior of previous core designs at PTN. The analytical models and methods from WCAP-9272-P-A[85] used by the licensee were identified as being previously approved by the NRC staff through the topical report review process. The licensee's application specifically addressed compliance with limitations and conditions imposed in the associated NRC staff safety evaluations regarding WCAP-9272-P-A and other topical reports. Although the NRC staff has accepted the reload safety evaluation methodology provided by WCAP-9272-P-A, the analytical codes for nuclear

[84] NRC Letter from D.G. McDonald, Jr., to J.W. Williams, Jr., Florida Power and Light Company, June 27, 1985.
[85] Bordelon, F. M, et al., "Westinghouse Reload Safety Evaluation Methodology,"
WCAP-9272-P-A (Proprietary) and WCAP-9273-NP-A (Nonproprietary), July 1985.

design referenced therein were written prior to the development of current fuel designs with higher enrichment limits. Therefore, the NRC staff issued RAIs requesting that the licensee assess the consistency of its analytical methods for nuclear design with current nuclear data and the fuel designs planned for use under proposed EPU conditions. By letters dated May 18,[86] and July 7, 2011,[87] the licensee's responses to these RAIs stated that, while the overall reload safety evaluation methodology outlined in WCAP-9272-P-A is being followed for the PTN EPU, the nuclear design codes referenced therein have been supplanted by more modern codes and are no longer used in current Westinghouse reload analyses. Specifically, the licensee stated that the PHOENIX-P/ANC code system[88] is currently used for Westinghouse reload analyses, and that the nuclear data files for the code system were updated in 1997.

The licensee referenced the May 9-14, 2010,[89] analysis demonstrating that subsequent updates to neutron cross section library files do not significantly affect core designs fueled with uranium oxide.

The licensee further stated that the PHOENIX-P/ANC code system has been extensively used and has performed well for core designs with a range of parameters that bound PTN at the proposed uprated condition. The licensee further stated that deviations between code predictions and measured data as a function of fuel enrichment have not been observed, nor are they expected from the physical models on which the code system is based. The staff considers the licensee's RAI responses to be acceptable because (1) the PHOENIX-P/ANC code system has been reviewed and found acceptable by the NRC staff, (2) the code system has been successfully used for the analysis of core designs with fuel enrichments and other parameters that envelop those of the proposed PTN EPU condition, and (3) the licensee has provided assurance that the cross section library employed by the code system is adequate for analyzing the proposed PTN EPU condition.

In accordance with the methods described above, the licensee stated that the resultant key safety parameters for PTN at EPU conditions show little change relative to the current design. The licensee further stated that variations in these safety parameters, including core power distributions, peaking factors, rod worths, and reactivity parameters, are similar to cycle-to-cycle variations expected in core loading patterns. Summarizing information available in the licensee's application, the table below provides a comparison of selected nuclear design parameters for the current configuration beside those of the proposed configuration following the EPU. The licensee noted that specific values of core safety parameters are loading pattern dependent, and that cycle-specific calculations will confirm that the actual values for each cycle are within the safety analysis limits.

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[86] ML111390661
[87] ML111920413
[88] Liu, Y.S., et al., "ANC: A Westinghouse Advanced Nodal Computer Code," WCAP-10965-P-A, September 1986, Nguyen, T.Q., et al., "Qualification of the PHOENIX-P/ANC Nuclear Design System for Pressurized Water Reactor Cores," WCAP-11596-P-A, June 1988.
[89] Huria, H.C., et al., "ENDF/B-VII Based Library for PARAGON," PHYSOR-2010 – Advances in Reactor Physics to Power the Nuclear Renaissance, Pittsburgh, PA, May 9-14, 2010

Parameter	Current Design Value	Proposed EPU Value
Reactor Core Power (MWt)	2300	2644
Maximum Fuel Enrichment (wt% ^{235}U)	4.5	5.0
Vessel Average Coolant Temperature at Hot Full Power (°F)	571.2 to 577.2	570.0 to 581.5
Reactor Coolant System Pressure (psia)	2250	2250
Core Average Linear Heat Rate (kW/ft)	5.84	6.714
Most Positive Moderator Temperature Coefficient (pcm/°F)		
Power ≤ 70%	+5.0	+5.0
Full Power (1)	0.0	0.0
Most Negative Moderator Temperature Coefficient (pcm/°F) (2)	-35	-41
Most Positive Moderator Density Coefficient ($\Delta k/k$ / g/cm^3)	0.50	0.50
Doppler Temperature Coefficient (pcm/°F)	-1.00 to -2.90	-1.00 to -2.90
Doppler Only Power Coefficient (pcm/%Power)		
Least Negative, Where Q is Power Level in Percent	-9.55+0.037Q	-9.55+0.037Q
Most Negative, Where Q is Power Level in Percent	-19.4+0.068Q	-19.4+0.068Q
Beta Effective	0.0042 to 0.0075	0.0044 to 0.0075
Nuclear Enthalpy Rise Hot Channel Factor, $F^N_{\Delta H}$, Normal Operation	1.700	1.650 / 1.352 (3)
Total Peaking Factor, $F_Q(Z)$, Normal Operation	2.50	2.40
Shutdown Margin (%$\Delta\rho$) (4)	1.77	1.77

Notes:

(1) Per TS LCO 3.1.1.3.c, the moderator temperature coefficient upper limit linearly decreases from +5.0 pcm/°F at 70% rated thermal power to 0 pcm/°F at 100% rated thermal power.

(2) Per TS LCO 3.1.1.3.d, this value is applicable for the all rods withdrawn, end of cycle, rated thermal power condition.

(3) Separate limits would be applied for the upgrade fuel assembly design (1.650) and the current debris resistant fuel assembly design (1.352).

(4) Per TS Figure 3.1-1, the value of 1.77%$\Delta\rho$ is applicable for an RCS boron concentration of 0 ppm.

Based on the key nuclear safety parameters determined from the licensee's calculations, which considered cores consisting of the new upgrade fuel assembly design as well as mixed cores also containing assemblies of the current fuel assembly design, the staff agrees that the nuclear design parameters for PTN would not experience large changes following the implementation of the proposed EPU. The staff further noted that the nuclear design parameters were in a range similar to other Westinghouse reactors that had recently received approval for EPUs, such as

Beaver Valley and Ginna, and that the licensee performs calculations each cycle to ensure that safety analysis limits are satisfied for the specified core design.

The results of the licensee's analysis of transient and accident conditions indicate that fuel design limits will not be exceeded during normal operation or anticipated operational occurrences, 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 acceptance of these conclusions is contingent upon the review and acceptance of the licensee's transient and accident analyses documented in Section 2.8.5 of this safety evaluation.

Additionally, two changes to the PTN technical specifications were proposed that the licensee considered as associated with the nuclear design:

(1) The licensee proposed revisions to LCO 3.1.1.3 and SR 4.1.1.3 associated with reducing the lower limit for the moderator temperature coefficient from -35 pcm/°F (i.e., -3.5×10^{-4} Δk/k /°F) to -41 pcm/°F.
(2) The licensee proposed revisions to LCOs 5.5.1.1 and 5.5.1.2 associated with increasing the permissible enrichment of fuel assemblies stored in the spent fuel storage racks or new fuel storage area to a maximum of 5.0 percent uranium-235 by weight.

A reduced lower limit for the moderator temperature coefficient has been proposed by the licensee to offset the increased reactivity associated with loading fuel assemblies of a higher enrichment. A lower limit on the moderator temperature coefficient is established to ensure acceptable fuel behavior during events involving moderator densification, which primarily results from excessive cooling of the reactor coolant system. The licensee has considered the impact of the reduced lower limit for the moderator temperature coefficient on the transients and accidents discussed in Section 2.8.5 of this safety evaluation. By letters dated November 8,[90] and November 10, 2010,[91] the NRC staff confirmed that the lower limit for the moderator temperature coefficient proposed by the licensee is comparable to plants of a similar design to PTN. However, it is ultimately the staff's review of transient and accident analyses associated with excessive cooling of the reactor coolant system, such as Section 2.8.5.1 (Increase in Heat Removal by the Secondary System) of this safety evaluation, that provides the technical basis for evaluating whether the proposed revisions to LCO 3.1.1.3 and SR 4.1.1.3 are acceptable. Therefore, acceptance of these proposed TS changes is contingent upon the staff's acceptance of the licensee's transient and accident analysis, which is addressed in Section 2.8.5 of this safety evaluation.

Regarding the changes proposed to LCOs 5.5.1.1 and 5.5.1.2, the staff considers the increased enrichment limit acceptable with respect to its effect on nuclear core design parameters. As demonstrated in the table above, the increased enrichment limit does not have a significant impact on key safety parameters applicable to the reactor core. The staff's review of the licensee's transient and accident analyses, which considers impacts of the increased enrichment limit, is reviewed separately in Section 2.8.5 of this safety evaluation. Other impacts

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[90] Dominion Letter from C.L. Funderburk to Document Control Desk, NRC, "Cycle 22 Core Operating Limits Report, Revision 1," November 8, 2010
[91] FENOC Letter from P.A. Harden to Document Control Desk, NRC, "Core Operating Limits Report, Cycle 21," November 10, 2010.

of the increased enrichment limit, such as the effect on criticality evaluations for the storage of new and spent fuel (Section 2.8.6), are also reviewed separately.

Based on the foregoing discussion, the staff considers the proposed TS changes associated with Section 2.8.2 to be acceptable with respect to the nuclear design; however, as noted, these proposed TS changes are also subject to review and acceptance in additional sections of this safety evaluation.

ASSESSMENT OF TCD ON NUCLEAR DESIGN

The licensee stated that the Westinghouse PHOENIX-P/ANC nuclear design system is the primary nuclear code system for nuclear design and safety analyses across the Westinghouse reactor fleet, both domestically and abroad. The benchmark data for the PHOENIX-P/ANC nuclear design system inherently included any effects of TCD. Therefore, the nuclear design PHOENIX-ANC nuclear design system was determined to remain valid and appropriate for nuclear design calculations. Accordingly, all nuclear design calculations previously performed to support the EPU design and safety analyses remain valid.

The licensee acknowledged that some limits have been revised as a result of TCD. Specifically, the power-to-melt kW/ft limits has been revised to be burnup dependent, the differential rod worth (reactivity insertion rate) limit has been reduced and the nuclear enthalpy rise hot channel factor ($F_{\Delta H}$) and the full-power heat flux hot channel factor (FQ) were reduced. As a result, these revised limits were confirmed to be satisfied for EPU cores for the affected non-LOCA accident analyses and Large Break LOCA.

The staff finds that the licensee's disposition for nuclear design is acceptable because the PHOENIX-P/ANC code system realistically incorporates the effects of TCD. The design limits discussed above were necessary to offset the effect TCD would have on certain design basis accidents and transients. As such, these restrictions are evaluated explicitly in other sections of this SE. The fuel melt limits are evaluated in Section 2.8.1; the revised reactivity insertion rate is discussed in Section 2.8.5.4.2 (rod withdrawal at power), and the reduced peaking factors were necessary to offset the TCD impact on the LBLOCA calculations as discussed in Section 2.8.5.6.3.1.

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 GDCs 10, 11, 12, 13, 20, 25, 26, 27, and 28. See the table in Section 2.8.5, Accident and Transient Analyses, Regulatory Evaluation to see the analogous

GDCs applicable to the Turkey Point GDCs. 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 reactor coolant system (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 anticipated operational occurrences (AOOs), and (4) is not susceptible to thermal-hydraulic instability. The review also covered hydraulic loads on the core and RCS components during normal operation and DBA conditions and core thermal-hydraulic stability under normal operation and anticipated transients without scram (ATWS) events. The NRC's acceptance criteria are based on (1) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (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.

NRC Technical Evaluation

To assure compliance with GDC 10, regarding adequate safety margin, the licensee chose to demonstrate that departure from nucleate boiling (DNB) will not occur on the most limiting (hot) fuel rod with a 95 percent probability at a 95 percent confidence level for any Condition I or Condition II event.

To accomplish this, the licensee used the revised thermal design procedure (RTDP) to analyze transient performance of DNB. The RTDP methodology, documented in WCAP-11397-P-A,[92] statistically accounts for system uncertainties in plant operating parameters, fabrication parameters, nuclear and thermal parameters, and critical heat flux (CHF) correlation and computer code uncertainties. In doing so, it yields a design-limit DNB ratio (DNBR). The term "DNBR" is defined as the predicted critical heat flux that would result in DNB divided by the actual heat flux being produced. If the calculated DNBR for normal operation or for a given transient is greater than the design-limit DNBR, then there is at least a 95 percent probability with a 95 percent confidence level that DNB will not occur on the most limiting fuel rod, maintaining the integrity of the fuel. Since it is the uncertainty in each parameter that is considered when determining the RTDP design-limit DNBR, the plant safety analyses, such as for normal operation, are performed using input parameters at their nominal values.

The licensee, when using the RTDP, also calculates a safety analysis limit (SAL) DNBR, which provides additional margin above the design-limit DNBR. The margin acts to offset the effects

[92] WCAP-11397-P-A, "Revised Thermal Design Procedure," April 1989. (AN ML080650330 (Proprietary))

of fuel rod bow and other DNBR penalties that may occur, as well as providing a margin for operational flexibility. The SAL DNBR, along with a calculated design-limit maximum nuclear enthalpy rise hot-channel factor ($F^N_{\Delta H}$), is used to develop core limits, axial offset limits, and dropped rod limits.

The licensee is implementing the RTDP using the NRC-approved Westinghouse version of the VIPRE-01 (VIPRE) code.[93] VIPRE has been approved by the NRC staff as a replacement for the THINC-IV and FACTRAN codes, provided that:

(1) the appropriate CHF correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel dependent parameters for a specific plant application are justified with each submittal,

(2) conservative reactor core boundary conditions, such as core inlet coolant flow and enthalpy, core average power, power shape and nuclear peaking factors, are input to VIPRE for reactor transient analysis, and

(3) the requirements for the use of new CHF correlations with VIPRE are satisfied.

For the first two provisions, the licensee has supplied and justified all the necessary parameters and inputs. Specifically, the licensee is using VIPRE with the WRB-1 CHF correlation.[94] The ABB-NV and WLOP CHF correlations[95] are also used, but only for analyses outside the range of applicability of the WRB-1. The ABB-NV correlation is applied for fuel assembly spans below the first mixing vane grid while the WLOP correlation is used when the pressure range is below that of the WRB-1. Westinghouse has met all the necessary requirements for use of the WRB-1, the ABB-NV and WLOP CHF correlations with the VIPRE code, satisfying the third provision above.

For those transient analyses where the RTDP was not applicable, the standard thermal design procedure (STDP) was used. The STDP uses a conservative deterministic methodology where the uncertainties of various plant and operating parameters are assumed simultaneously at their worst uncertainty limits in the safety analyses.

The licensee’s request for an extended power uprate (EPU) includes a transition from the current fuel design of Westinghouse 15×15 seven-grid Debris Resistant Fuel Assemblies (DRFA) to Westinghouse 15×15 seven-grid upgrade fuel assemblies. This will be implemented through a mixed core of DRFA and upgrade fuel.

The thermal-hydraulic analyses utilizing the RTDP and STDP methodologies were performed at EPU conditions with cores containing upgrade fuel. The analyses assume cores may contain a mix of both upgrade fuel assemblies and residual DRFA fuel assemblies from pre-uprate cycles.

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[93] WCAP-14565-P-A, “VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis,” October 1999. (AN ML993160153 (Proprietary)).
[94] WCAP-8762-P-A, “New Westinghouse Correlation WRB-1 for Predicting Critical Heat Flux in Rod Bundles with Mixing Vane Grids,” July 1984. (AN ML080630433 (Proprietary)).
[95] WCAP-14565-P-A, “Addendum 2-P-A, Extended Application of ABB-NV Correlation and Modified ABB-NV Correlation WLOP for PWR Low Pressure Applications,” April 2008. (AN ML081280713 (Proprietary))

Because fresh fuel assemblies of upgrade fuel in a mixed core at uprated conditions will have higher peaking factors than residual DRFA fuel from pre-uprate cycles, the upgrade fuel will bound the DRFA fuel.

Key features of the DRFA and upgrade fuel designs are compared in Table 2.8.1-1 of the EPU license amendment request (LAR). The upgrade fuel, possessing both IFM-Grids and P-Grids, has a different hydraulic diameter from the DRFA fuel causing flow redistribution between the different fuel assemblies. A reduced flow will exist in the higher-resistance assemblies, which will have an impact on DNB. Through the use of a transition core penalty, the licensee takes into consideration the fuel hydraulic diameter differences and impact on DNB during the transition from an all DRFA fuel core through mixed fuel cores to an all upgrade fuel core. The NRC staff issued a request for additional information (RAI) on how the transition core DNBR penalty was determined.

By letter dated May 18, 2011,[96] the licensee's response to this inquiry indicated that transition core DNBR penalties are calculated according to the NRC-approved methodology described in WCAP-11837-P-A.[97] This approach models core configurations with varying numbers of the transitioning fuel assemblies. A DNBR penalty is calculated for each configuration resulting in a plot of DNBR penalty versus fraction of transitioning fuel assemblies in the core. The licensee indicated these calculations were performed for the DRFA and upgrade fuel assemblies used in the transition core and supplied plots and equations of the resulting transition core DNBR penalties.

The methodology presented in WCAP-11837-P-A was established using the improved thermal design procedure (ITDP) and THINC-IV code. In a conference phone call with the licensee and Westinghouse on July 12, 2011, it was stated the transition core DNBR penalties analyses were performed using the RTDP and the VIPRE code, which the NRC staff has approved as an improvement upon the ITDP[98] and a replacement for THINC-IV, respectively.

According to WCAP-11837-P-A, the DNBR penalty is to be applied to the penalizing assembly, which is the assembly having localized flow redistribution away from itself. The licensee indicated in their RAI response that the DRFA fuel experiences flow redistribution in the lower grid spans towards the upgrade fuel and that the upgrade fuel experiences flow redistribution in the upper grid spans towards the DRFA. As a result, both fuel assemblies are penalizing. The licensee therefore calculates and applies individual transition core penalties to both fuel types. The licensee also states that during reload safety analyses a cycle-specific penalty will be calculated for each fuel type based on the transition core DNBR penalties equations supplied in their RAI response. The NRC staff considers the licensee's use of the WCAP-11837-P-A methodology with the RTDP and VIPRE in the calculation of transition core DNBR penalties and the application of these penalties to both DRFA and upgrade fuel assemblies on a cycle-specific basis to be acceptable.

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[96] ML11139A344
[97] WCAP-11837-P-A, "Extension of Methodology for Calculating Transition Core DNBR Penalties," January 1990. (ML092040126 (Proprietary)).
[98] WCAP-11937-P-A, "Revised Thermal Design Procedure," April 1989. (ML080650330 (Proprietary)).

Rod bow, which can occur in between fuel assembly grids, reduces the spacing between adjacent fuel rods, thereby reducing the margin to DNB. A rod bow DNB penalty is applied by the licensee to account for this reduction in margin. In spans containing IFM grids in the upgrade fuel, the licensee does not apply the rod bow DNB penalty because of the short spacing between the grids. Further support for this approach was requested by the NRC staff.

By letter dated May 18, 2011, the licensee stated that use of the Westinghouse rod bow scaling factor documented in WCAP-8691-R1[99] resulted in a predicted channel closure of less than 50 percent within the IFM grid spans. Fuel rod channel closures of 50 percent or less show no reduction in the CHF at which DNB occurs and therefore no DNBR penalty due to rod bow is needed in the IFM grid spans. The NRC staff considers this response acceptable.

The applicability of the WRB-1 CHF correlation to Westinghouse Upgrade Fuel is documented in LTR-NRC-04-8.[100] The ABB-NV and WLOP CHF correlations are also applicable to Westinghouse Upgrade Fuel.

The WRB-1, ABB-NV, and WLOP CHF correlation-limit DNBRs are 1.17, 1.13, and 1.18, respectively, and are used with the STDP. These values apply to both DRFA and upgrade fuel assemblies. When using the RTDP, the WRB-1 correlation limit of 1.17 is considered statistically with other plant-specific parameters that affect DNB to yield a design-limit DNBR of [[ ]] for the upgrade design and [[ ]] for the DRFA design. The SAL DNBR was determined to be [[ ]] for the upgrade design and [[ ]] for the DRFA design.

The DNBR margin/penalty summary for steady state using the RTDP with the WRB-1 CHF correlation is given in Table 2.8.3-5 of the LAR. The DNBR margin/penalty summary for transients using the STDP with the ABB-NV and WLOP CHF correlations are presented in Table 2.8.5.0-1 of the LAR.

To assure compliance with GDC 12, regarding power oscillations, the potential for possible spatial oscillations of power distribution was reviewed against the PTN UFSAR, Chapter 3, Reactor,[101] and it was concluded that:

- Low frequency xenon oscillations, which may occur in the axial direction, can be controlled by control rod movement.

- The core is expected to be stable to xenon oscillations in the X-Y dimension.

- Excore Instrumentation is provided to obtain necessary information concerning power distribution and that the instrumentation is adequate to enable the operator to monitor and control xenon induced oscillations.

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[99] WCAP-8691-R1, “Fuel Rod Bow Evaluation,” July 1979. (AN ML080630443 (Proprietary)).
[100] Letter from Westinghouse Electric Company, LTR-NRC-04-8, “Fuel Criterion Evaluation Process (FCEP) Notification of the 15×15 Upgrade Design (Proprietary),” February 2004. (AN ML040430428 (Proprietary)).
[101] UFSAR, “Turkey Point, Units 3 and 4, Updated Final Safety Analysis Report – Unit 4 Cycle 24 Update, Chapter 3, Reactor.” September 2010, (ML102870305 (Non-Proprietary)).

The NRC staff finds the use of the WRB-1, ABB-NV, and WLOP CHF correlations, the RTDP and STDP methodologies, and the thermal-hydraulic sub-channel analysis code, VIPRE, to be acceptable and in accordance with NRC-approved methods. The thermal-hydraulic evaluation of PTN Units 3 and 4 at EPU conditions showed that sufficient DNB margin is available when using the CHF correlations at EPU conditions. The NRC staff has determined that the CHF correlations used in these analyses are appropriate for the core conditions, the analysis methods in use account for the relevant uncertainties in an acceptable manner, and that the licensee has considered the effects of transition core flow redistribution at EPU conditions. Based on the results presented in the LAR, and on the knowledge that cycle-specific core analyses will be performed in accordance with NRC-approved methods, the NRC staff concludes that the thermal and hydraulic design meets the requirements of GDC-10 and GDC-12 at EPU conditions. Specific transients and accidents are further evaluated in Section 2.8.5 of this safety evaluation.

ASSESSMENT OF TCD ON FUEL THERMAL HYDRAULIC DESIGN

The licensee conducted a review of the license amendment request for Turkey Point Units 3 and 4, specifically, Licensing Report Section 2.8.3, to evaluate the impact of TCD.

The licensee stated that TCD has no direct impact on the steady-state VIPRE models. The licensee offered this conclusion because VIPRE does not explicitly model the fuel rod, but rather models the rod surface heat flux.

The effects of fuel stored energy and rod conduction heat transfer are significant in fast transients such as complete loss of flow and locked rotor events; therefore, a transient VIPRE model is used for those two analyses. The licensee explained that, in a transient VIPRE model, fuel rods can be modeled using the option of conducting rod. The conducting rod option allows the user to specify a number of radial nodes in the pellet, and a gap conductance model for the heat transfer between the pellet and the inner surface of the cladding. The initial gap conductance values in the transient VIPRE model are based on conservative maximum fuel temperatures (including uncertainties) from the PAD 4.0 code. The PAD 4.0 fuel pellet surface temperature is used to determine the VIPRE gap conductance at each axial node. The TCD impacts on the transient VIPRE analyses are discussed in Section 2.8.5.3 of this SE.

The staff accepts the licensee’s conclusions regarding the TCD impact on fuel thermal hydraulic design. Since the steady state VIPRE model considers fuel surface heat flux, it is relatively insensitive to the fuel centerline conditions. Although the transient VIPRE analyses use inputs from PAD 4.0, they model initial conditions that are based mostly on the beginning of cycle fuel rod conditions, including the maximum fuel temperature, peaking factor, and reactivity feedback conditions. Taken together, these analytic inputs produce a set of initial conditions that will likely bound the effects of TCD.

Beyond the model inputs, there is also substantial safety margin between the safety analysis limit for DNBR and the DNBR safety limit in the Technical Specifications. By contrast, the licensee’s LOCA analyses were approaching the regulatory limits for peak cladding temperature, a condition that warranted the more thorough, quantitative evaluation that the licensee performed for the LOCA events. The LOCA analyses are discussed in Section 2.8.5.6.3.1.

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 thermal-hydraulic 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 GDCs 10 and 12 following implementation of the proposed EPU. See the table in Section 2.8.5, Accident and Transient Analyses, Regulatory Evaluation to see the analogous GDCs applicable to the Turkey Point GDCs. 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

The impact of EPU on the control rod drive system (CRDS) results from temperature effects of increasing reactor thermal power associated with an increase in reactor coolant system (RCS) outlet temperature. The licensee intends to demonstrate that the increase in the RCS outlet temperature does not result in any adverse effects on the CRDS.

Fuel Related Impact

The EPU will have no impact on the full down position of the rod cluster control assemblies (RCCAs) relative to the fuel assembly, and the fuel assembly interface with the RCCA remains unchanged. The upper end fitting of the fuel assembly remains unchanged. Thus, there is no impact on the RCCA position due to transition to the upgrade fuel design for EPU. As a result of EPU, the licensee determined that there is no fuel-related impact to the control rod drive system (CRDS).

The NRC staff reviewed the licensee's assessment and concludes that there is no fuel-related impact to the CRDS at EPU conditions.

Control Rod Drive Mechanism

The control rod drive mechanisms (CRDMs) use electro-magnetic coils to position the RCCAs within the reactor core. The licensee recently modified the CRDM cooling systems as part of the reactor head replacement projects at both units. For both current and EPU conditions, the CRDM cooling system is designed to maintain the CRDM electro-magnetic coils at a temperature below 392 °F.

The licensee analyzed the CRDM cooling system using a computational fluid dynamics computer code to verify that the modified system provided sufficient cooling to the CRDM electro-magnetic coils. The results showed that the maximum CRDM temperatures for current and EPU conditions were below 392 °F. The licensee determined that there was sufficient cooling to the CRDM electro-magnetic coils.

The staff reviewed the licensee's analysis and determined that the design temperature in the CRDM electro-magnetic coils, used to move the control rods, was not exceeded. Based on the acceptable analysis, the staff concludes that the modified CRDM cooling systems are acceptable for current and EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's functional design of control rod drive system for PTN Units 3 and 4 at EPU in the submitted licensing report. Based on the evaluation, the staff concludes that the functional design of control rod drive system is acceptable for PTN Units 3 and 4 at EPU.

2.8.4.2 Overpressure Protection At Power Operation

Regulatory Evaluation

Overpressure protection for the reactor coolant pressure boundary (RCPB) during power operation is provided by relief and safety valves and the reactor protection system (RPS). The NRC staff's review covered pressurizer relief and safety valves and the piping from these valves to the pressurizer relief tank, and the RCS relief and safety valves.

For overpressure protection during power operation, the RS-001 guidance advises the staff to apply review acceptance criteria that are based upon the requirements of GDC 15, and GDC 31. However, the staff is directed, by the Commission,[102] not to apply the GDCs of 10 CFR Part 50, Appendix A, to plants with construction permits that were issued prior to May 21, 1971. It was determined that backfitting the GDCs would provide little or no safety benefit while requiring an extensive commitment of resources. Construction permits, for both PTN units, were issued in April 1967.

PTN is designed in accordance with GDCs that were proposed by the Atomic Energy Commission (AEC) in 1967. The 10 CFR Part 50, Appendix A criteria that relate to overpressure protection during power operation are GDC-15, "Reactor Coolant System Design," and GDC-31, "Fracture Prevention of Reactor Coolant Pressure Boundary."

There is no GDC in the PTN design basis that directly corresponds to GDC-15.

The licensee's UFSAR Section 4.1.3 indicates that the RCS is protected from overpressure by means of pressure relieving devices, as required by Section III of the American Society of Mechanical Engineers (ASME) *Boiler and Pressure Vessel Code*. UFSAR Section 4.2.3

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[102] U.S. Nuclear Regulatory Commission, "Resolution of Deviations Identified During the Systematic Evaluation Program," Commission Paper SECY-92-223, September 18, 1997, ADAMS Accession No. ML003763736.

describes the overpressure protection that is provided by automatic control systems (e.g., pressurizer spray, and pressurizer power-operated relief valves (PORVs)), and the RPS (e.g., the high pressure reactor trip, and the code pressurizer safety valves). The PORVs and code safety valves discharge into the pressurizer relief tank which condenses the steam and collects the condensate

GDC-31 corresponds to PTN GDC-34 in the PTN design basis. Both GDCs, along with all the other GDCs that are identified in RS-001, are compared in Section 2.8.5, “Accident and Transient Analyses,” of this safety evaluation.

The NRC staff also refers to SRP Section 5.2.2, and to Matrix 8 of RS 001, to guide its review of the overpressure protection during power operation analysis, particularly with respect to operation under EPU conditions. The Standard Review Plan and RS-001 had not yet been written in 1973, the year by which both of the PTN operating licenses were issued. Consequently, the staff’s application of this guidance takes into account the specific GDCs to which the PTN units were designed and licensed.

NRC Technical Evaluation

Protection against overpressurization of the RCPB is afforded, principally, by tripping the reactor (by means of automatic trip signals from the RPS), and by relieving steam through the pressurizer safety valves. The safety valves are sized to limit pressurization of the RCPB to less than 110 percent of its design pressure, in accordance with Section III of the ASME Boiler and Pressure Vessel Code. For the PTN units, the RCS pressure limit is 2748.5 psia, and the steam system pressure limit is 1208.5 psia.

The complete loss of load without a direct reactor trip, or loss-of-electrical-load/turbine-trip (LOL/TT) event is the AOO that produces the highest peak primary and secondary system pressures in the PTN units. SRP Section 5.2.2, and Matrix 8 of RS-001, indicate that this event analysis should be based upon the assumption that the reactor is not tripped from either (1) the reactor trip signal that is generated directly from the turbine trip, or (2) the first safety-grade reactor trip signal from the reactor protection system (e.g., the high pressurizer pressure trip). Waiting for the second safety-grade reactor trip signal from the reactor protection system (e.g., the overtemperature (OT) ΔT trip) to trip the reactor demonstrates that there is more margin to the pressure safety limits, and that there is defense-in-depth in the reactor protection system design, insofar as the second safety grade trip signal, based upon another RCS condition, provides adequate protection against overpressure.

The staff asked the licensee to provide the analysis that is described in SRP Section 5.2.2. The licensee declined to provide the requested analysis, and reminded the staff that the PTN units were licensed before any of the SRPs were issued. The staff notes that, in the absence of an SRP Section 5.2.2 or equivalent, adequate overpressure protection, for the PTN units, can be demonstrated by the LOL/TT analysis that is evaluated in LR Section 2.8.5.2.1. This analysis, based upon the first safety-grade signal received from the reactor protection system (derived from the high pressurizer pressure condition), shows that the primary and secondary system pressures remain below 110 percent of their respective design pressures at all times during the transient. Although the LOL/TT analysis of LR Section 2.8.5.2.1 shows that the PTN units will have adequate overpressure protection at the proposed EPU power level, it does not, however,

demonstrate the added margin that comes from waiting for the second reactor trip signal, and does not demonstrate that there is defense-in-depth, with respect to overpressure protection, in the PTN design.

Conclusion

The NRC staff has reviewed the limiting analysis that is related to the effects of the EPU on the overpressure protection capability of the PTN plants during power operation. The NRC staff concludes that the LOL/TT analysis of LR Section 2.8.5.2.1 has adequately accounted for the effects of the proposed EPU with respect to overpressure protection, within the context of the PTN design basis. Therefore, the overpressure protection features will continue to provide adequate protection with respect to PTN GDC 34 following implementation of the proposed EPU.

The proposed EPU is found to be acceptable with respect to overpressure protection during power operation under EPU conditions.

2.8.4.3 Overpressure Protection for 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 quench tank, the makeup and letdown system, and the residual heat removal (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.

The aforementioned GDCs, published in 10 CFR 50, Appendix A, were not yet available at the time the PTN units were licensed to operate. The PTN units were designed and licensed according to earlier GDCs, proposed by the Atomic Energy Commission, that are discussed in PTN FSAR Section 1.3. In this case, the GDC equivalents for GDCs 15, and 31 are proposed GDCs 9, 33, and 34.

Specific review criteria are contained in SRP Section 5.2.2 and Matrix 8 of RS-001.

NRC Technical Evaluation

PTN TS 3.4.9.3 requires the low temperature overpressure protection (LTOP) system to be operable in MODES 4 (when any RCS cold temperature is less than or equal to 275 °F), 5, and 6, with the reactor vessel head on. It precludes injection from the high pressure safety injection system and requires one of two pressure relief capabilities. Either two power-operated relief valves with lift settings as established in the specification must be available, or the RCS must be depressurized with a vent path that has a capability equivalent to or greater than a PORV.

The licensee stated that the LTOP system is designed to mitigate two types of transients. These transients are mass input arising from injection sources such as charging pumps, safety injection pumps, or SI accumulators, and heat input transients from sources such as steam generators, decay heat, or pressurizer heaters. The transients assume that the residual heat removal system is isolated from the RCS, and while the pressure relief capacity is not available, the RHR pumps are similarly isolated and unable to add mass to the RCS.

For each of the mass and heat input transients, calculations are made for pressure overshoots during the delay time before the relief valve starts to move and during the time the valve is moving to the full open position. The calculated pressure overshoots are then used to determine the PORV opening setpoints to ensure adequate pressure relieving capacity. This calculational framework is NRC-approved and in accordance with Westinghouse licensing topical report WCAP-14040-A.[103]

The limiting mass input transient is postulated to be the isolation of the letdown system with continued operation of one high head safety injection pump; the limiting heat input transient is the heat input associated with a 50 °F temperature asymmetry between the steam generator and the primary side water temperatures. These analyses establish the limiting conditions for operation (LCOs) of the low temperature overpressure protection system. Specifically, LCO 3.4.9.3 requires isolation of the high head safety injection flow paths, and LCO 3.4.1.3 restricts starting a reactor coolant pump with a secondary water temperature that exceeds the primary water temperature by more than 50 °F.

Previous analyses determined that the mass injection transient was limiting with respect to cold overpressure protection. The licensee evaluated the effects of the proposed power uprate on the previous analyses, and determined that the mass injection flow rates would increase slightly by approximately 10 gallons per minute (gpm). Since the primary-secondary temperature requirements in TS 3.4.1.3 remain unchanged, the heat input transient is unaffected by the proposed EPU. Because the licensee accounted for the effects of the proposed EPU on the mass input transient, and concluded that the EPU would not affect the heat input transient, the NRC staff finds the licensee evaluation of the cold overpressure mitigation system acceptable for the proposed EPU.

As discussed above, the LTOP system setpoints are determined in accordance with the NRC-approved method described in WCAP-14040-A, Revision 2, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit

[103] Andrachek, J. A., et al., Westinghouse Electric Company, “Methodology to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Curves,” WCAP-14040-A, Revision 4, May 2004. ML050120209.

Curves." Reactor vessel neutron fluence, accordant with the above methodology, is an input to the reactor vessel material evaluations that determine the setpoints. The reactor vessel neutron fluence analysis can be affected by a significant change in core operation, so the NRC staff requested that the licensee explain how current fluence analysis accounts for the EPU.

In response, the licensee stated that a plant-specific calculation was performed for fuel cycles that have been completed, and fluence projections for future operation were generated based on an assumed mode of operation.[104] Specifically, spatial power distributions and core power level for uprated core designs were used to determine the neutron exposure during future operation. The uprated core designs were based on expected fuel management strategies for the uprate. Because the licensee confirmed that the EPU fluence projections account explicitly for future operation, the staff finds the licensee's assessment of the EPU fluence acceptable insofar as it supports the low temperature overpressure protection system setpoints.

Based on the following considerations:

- The requested EPU does not affect the low temperature overpressure protection limiting conditions for operation;
- The licensee has proposed RCS pressure and temperature limits that were generated in accordance with NRC-approved methodology; and
- The fluence calculations providing input to the LTOP analyses are acceptable with respect to the EPU core design,

The NRC staff finds the requested EPU acceptable with respect to low temperature overpressure protection.

The staff did not locate TS limiting conditions for operation or surveillance requirements pertaining to the accumulators while in the LTOP-enabled operating modes. The staff expects that the licensee administratively ensures that the accumulators are isolated and that the isolation is periodically surveillanced in the appropriate modes. Because the requirement appears not to exist in the current PTN TS, the NRC staff did not request additional information concerning the TS requirements on the accumulators while in the LTOP-enabled operating modes.

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. In large part, the EPU does not include design changes that affect the limiting low temperature overpressure events, or the plant's mitigating features to protect from such events. Based on this, the NRC staff concludes that the low temperature

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[104] Kiley, Michael, FPL, letter to U.S. NRC, "Response to NRC Request for Additional Information Regarding Extended Power Uprate License Amendment Request Number 205 and Reactor Systems Issues," FPL Reference L-2011-141, Dockets 50-250 and 50-251, May 11, 2011. ML11137A080.

overpressure protection features will continue to provide adequate protection to meet PTN GDC 9, 33, and 34 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to overpressure protection during low temperature operation.

2.8.4.4 Residual Heat Removal

Regulatory Evaluation

The RHR system is used to cool down the RCS following shutdown. The RHR system is typically a low pressure system which takes over the shutdown cooling function when the RCS temperature is reduced. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the RHR system to cool the RCS following shutdown and provide decay heat removal.

The NRC's acceptance criteria are based on:

(1) GDC-4, insofar as it requires that SSCs important to safety be protected against dynamic effects;

(2) GDC-5, insofar as it requires that SSCs important to safety not be shared among nuclear power units, unless it can be shown that 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 residual heat removal systems.

The aforementioned GDCs, published in 10 CFR Part 50, Appendix A, were not yet available at the time the PTN units were licensed to operate. The PTN units were designed and licensed according to earlier GDCs, proposed by the Atomic Energy Commission, that are discussed in PTN FSAR Section 1.3.

In this case, the GDC equivalents for GDCs 4, 5, and 34 are the earlier PTN GDC-40 and- 4 criteria. However, the licensee stated that the FSAR does not directly apply these criteria to the decay heat removal function of the residual heat removal system. PTN GDC-4 pertains to shared systems. The licensee stated that the RHR system and components are unit specific and are not shared between units. PTN GDC-40 is titled "Missile Protection" and addresses adequate protection against dynamic effects and missiles that might result from plant equipment failures other than a rupture of the reactor coolant system. The licensee stated that:

> PTN has no plant specific GDC analogous to GDC-34 requiring a RHR System but a RHR System is provided in the plant design as described in UFSAR Sections 6.2 and 9.3 as part of the Engineered Safety Feature (ESF) Safety Injection System (SIS) and as part of the Auxiliary Cooling Systems, respectively.

Specific review criteria are contained in SRP Section 5.4.7 and other guidance is provided in Matrix 8 of RS-001.

NRC Technical Evaluation

The licensee stated that "the RHR loop is designed to remove residual and sensible heat from the core and reduce the temperature of the RCS during the second phase of plant cooldown after RCS temperature and pressure have been reduced to 350 °F and 450 psig, respectively."

The RHR system evaluation is stated to include the following assumptions:

(1) No secondary side heat removal below 350 °F RCS temperature during cooldown.

(2) Perfect RCS water mixing so that there are no hot spots.

(3) Heat exchanger rates consistent with the maintenance program with respect to fouling.

(4) A seasonally adjusted inlet water cooling system temperature range of 92 °F to 97 °F.

(5) The CCW System supply temperature is limited to 125 °F during plant cooldown.

(6) Seasonally adjusted auxiliary heat loads that are expected to exist during plant cooldown are included in the total heat load that is imposed on the CCW System.

RHR cooldown rates in hours after reactor shutdown are stated to be as follows:

Cooldown Process	EPU	Current	Acceptance Criterion
Normal two trains to 140 °F*	107	83	None
Normal two trains to 200 °F*	28	30	None
Tech Spec cooldown to 200 °F	28	30	36
Appendix R cooldown to 200 °F**	38	33	72
* Initiation 7 hours after shutdown. **One train, initiation 25.5 hours after shutdown.			

With respect to reduced inventory operation, PTN stated: "The EPU has no effect on the ability of the RHR system to remove residual heat at reduced reactor coolant system inventory, and therefore the PTN will continue to meet the current licensing basis requirements with respect to NRC Generic Letter 88-17." This statement is not substantiated by information originally submitted to support the EPU amendment request and is addressed further below.

The NRC staff posed several questions regarding RHR behavior if thermal power is increased. A summary of the questions and the licensee's responses,[105, 106] followed by the NRC staff assessment, follows.

The staff requested that the licensee justify the uniform RCS temperature assumption with respect to the core, upper plenum, upper head, and the pressurizer for both RCPs running and

[105] ML11137A080.
[106] Kiley, Michael, FPL, letter to U.S. NRC, "Response to NRC Request for Additional Information Regarding Extended Power Uprate License Amendment Request No. 205," FPL Reference L-2011-369, Dockets 50-250 and 50-251, September 16, 2011. ML11263A003.

not running. Include a discussion of the implications where RCS temperature is not uniform and equal to average RCS temperature in the hot legs. Include drain down of RCS inventory and emptying the pressurizer in this discussion.

In response, the licensee explained that this assumption is used for the RCS cooldown analyses. The RCS is modeled as a lumped heat source with a conservative, single-valued heat capacity and results are consistent with many years of PWR plant cooldown performance from many reactor-years of PWR plant operation. It is not intended to provide temperature profiles during RHR operation. Since a typical cooldown rate is approximately 1 ºF/minute, significant RCS temperature differences will not occur. In these cooldowns, pressurizer level is procedurally maintained and the pressurizer is not drained. This is conservative since it maximizes the water mass and, therefore, the RCS heat capacity.

It is the staff's assessment that pressurizer, reactor vessel metal, and upper head temperature may lag predicted temperature but including the heat capacities of these in the cooldown analysis will delay predicted cooldown time, a conservative response. The remainder of the RCS will be reasonably uniform. The uniform temperature assumption is acceptable since it will extend predicted cooldown time in comparison to actual behavior.

The staff noted that the predicted normal cooldown time is 28 hours versus the existing lower heat load cooldown time of 30 hours. The staff requested that FPL explain, since the expectation is that an increased heat generation rate would result in a longer cooldown time.

In response, the licensee stated that the updated analysis for the EPU also includes other system and component design input changes, all of which affect the cooldown results. These additional changes include seasonally adjusted best-estimate values of the maximum Intake Cooling Water (ICW) system supply temperature and auxiliary plant heat loads that more accurately reflect the actual operation of the plant. The analysis assumes that the maximum ICW temperature (which occurs in the summer) does not occur concurrently with the maximum auxiliary heat load (which is from the spent fuel pool and PTN refueling outages normally occur in the spring or fall). The previous cooldown analysis did not consider these refinements in the analysis inputs.

The staff finds that the PTN response, in conjunction with additional information that is not included in the above summary, is sufficient to justify the reported cooldown time.

Sections 2.8.4.4.2.3 and 2.8.4.4.2.5 state that there are no safety-related design criteria for normal plant cooldown times and, therefore, the calculated cooldown times are acceptable. Yet Section 2.8.4.4.2.5 also states a technical specification (TS) time limit for achieving cold shutdown of 6 + 30 = 36 hours after reactor shutdown and states that the 28 hours applies. Therefore, the staff requested that FPL explain the rationale for concluding that calculated cooldown times are acceptable since there are stated to be no safety-related design criteria in contrast to using these results for meeting TS and other cooldown criteria.

The licensee stated in response that the current licensing basis for Chapter 14 events defines safe shutdown as hot standby. Thus, cooldown to cold shutdown is not addressed for these events. Cold shutdown is addressed for Appendix R. Accordingly, various cooldown scenarios were addressed in the EPU LAR and two are considered to be quality-related analyses:

1) normal plant TS cooldown to cold shutdown within 36 hours, and 2) an Appendix R cooldown to cold shutdown within 72 hours. As stated in LR Section 2.5.1.4, the cooldown analysis performed for the Appendix R cooldown demonstrates that cooldown to cold shutdown would be accomplished within 63.5 hours, meeting the 72-hour acceptance criteria.

The staff finds that the response acceptably explains the cooldown times.

There appears to be no information that addresses the effect of the EPU on heat exchanger fouling factors. The staff requested that the licensee address the behavior of heat exchanger fouling factors due to the higher heat load, longer cooldown times, and greater differential temperatures.

Heat exchanger fouling factors typically are a function of water chemistry and cleanliness, which will not change due to the EPU conditions, according to the licensee response. Early in the cooldown the fouling factors are not affected by heat load, cooldown times, or differential temperatures because RHR flow rate is throttled as needed to meet (a) a maximum RCS cooldown rate of 50 °F per hour, and (b) a maximum CCW supply temperature of 125 °F.

The licensee stated that the CCW and RHR heat exchanger heat transfer rates assume fouling factors that are consistent with the maintenance program and TS surveillance requirements for these heat exchangers. Monitoring is accomplished by recording intake cooling water (ICW) and CCW conditions. Allowance for fouling is accomplished by reducing the maximum allowable ICW inlet temperature by 0.5 °F per day. Heat exchangers are scheduled for cleaning before margin between the allowable ICW and actual ICW temperatures approaches 3 °F. In addition, TS Action 4.7.2 requires verification at least once every 12 hours that two CCW heat exchangers and one CCW pump can remove design basis heat loads.

A licensee historical data review indicated that there is adequate margin between the observed fouling factor and maximum allowable fouling factor. The monitoring and trending program ensures that the worst pair of CCW heat exchangers will continue to remove the design basis heat load at the average canal temperature. Hence, the marginally longer plant cooldown times associated with the EPU conditions are not expected to have a significant effect on the heat exchanger fouling factors. Further, plant operating data supports the judgment that there will be no significant increase in fouling of the CCW heat exchanger over the course of a normal plant cooldown.

The staff's concern is the effect of running at a maximum CCW temperature of 125 °F for a longer time followed by some time at higher temperature toward the end of cooldown. This can affect fouling on the ICW side of the CCW/ICW heat exchanger. The excess cooling capacity, as shown by the need for throttling early in cooldown, establishes that fouling is not a concern during early cooldown.

PTN did not clearly establish how fouling factors could change or how such changes would perturb cooling characteristics. However, the maintenance program and TS action requirement, in combination with the decreasing allowable ICW inlet temperature that requires cleaning if the margin between actual and allowable ICW inlet temperature approaches 3 °F, and the margin between predicted cooldown times and cooldown requirements, is judged to reasonably ensure meeting RHR operability requirements.

FPL states that the EPU has no effect on the ability of the RHR system to remove residual heat at reduced reactor coolant system inventory; and, therefore, the PTN plants will continue to meet the current licensing basis requirements with respect to NRC Generic Letter 88-17. The staff requested justification of this conclusion in light of the increased decay heat generation rate that must be removed after shutdown. The staff specifically requested that the licensee consider the effect on temperature, RHR flow rate including any limitations on flow rate as a function of RCS water level, and potential hot leg vortexing in the justification.

The licensee stated in response that RCS water level could be reduced within less than 2 days of full power operation when the decay heat generation rate will be less than 1 percent of the full power heat load and, therefore, not significantly different than that associated with the current licensed power level. Thus, the RHR flow rate required to remove decay heat at that time will also not differ significantly and will remain within current PTN procedure and technical specification limits.

In regard to reduced inventory operation, the licensee noted that the level of coolant that is maintained in the RCS loop piping during reduced inventory conditions is unchanged under EPU conditions. Other system parameters that are relevant to vortex formation in the RHR suction line (i.e., pipe diameter, water level, and fluid flow rate and velocity) also are unchanged as a result of the EPU. There has been no change to the licensing basis of the plant for reduced inventory operation as a result of the EPU. PTN Technical Specification 3/4.9.8.2 remains applicable to refueling operations with low water level under EPU conditions. Therefore, the licensee concluded that the EPU has no effect on the ability of the RHR system to remove residual heat at reduced reactor coolant system inventory, and PTN will continue to meet the current licensing basis requirements with respect to NRC Generic Letter 88-17.

The licensee also stated that plant operating procedures currently require a minimum shutdown time of 60 hours before entry into reduced inventory is permitted. Under EPU conditions, the plant will be required to remain shutdown for 126 hours before entering reduced inventory.

FPL's conclusion was essentially that a 15 percent increase in decay heat generation rate would have no effect on the RHR system operation during reduced inventory operation, a conclusion that was not justified since the implication was that reduced inventory could be entered from EPU conditions two days after shutdown, the same time as before the uprate. However, additional information indicated that delaying minimum entry time for entry into reduced inventory by 66 hours reduces heat generation rate to less than would exist without the uprate. This means operating conditions at reduced inventory will not be potentially more challenging than prior to EPU operation and it is not necessary to reconsider such effects as time to saturation, boil-off rate, and make-up capability since these have been previously addressed for current operation.

On the basis of a minimum entry time into reduced inventory of 126 hours and no other changes in RHR operating conditions, the proposed reduced inventory operation is acceptable.

Conclusion

The NRC staff concludes that the licensee adequately accounted for the effects of the proposed EPU on the RHR system and demonstrated that the RHR system will maintain its ability to cool the RCS following shutdown and provide decay heat removal. Based on these considerations, the NRC staff concludes that the RHR system will continue to meet the requirements of GDC-4, 5, and 34 following implementation of the proposed EPU. See the table in Section 2.8.5, Accident and Transient Analyses, Regulatory Evaluation to see the analogous GDCs applicable to the Turkey Point GDCs. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RHR system.

2.8.5 Accident and Transient Analyses

Regulatory Evaluation

This Safety Evaluation generally follows the format guideline of RS-001. RS-001, and particularly Matrix 8 of RS-001, identify the General Design Criteria (GDCs) and Standard Review Plan sections that pertain to each of the accident and transient analyses.

These GDCs are defined in 10 CFR Part 50, Appendix A, which was issued in 1971. However, the NRC had granted FPL Construction Permits for the PTN units in 1967. The PTN GDCs are based on the 1967 Atomic Energy Commission (AEC) Proposed General Design Criteria, as amended by the Atomic Industrial Forum, and published on October 2, 1967.

The accident and transient analyses that are addressed in this section are governed by the 17 GDCs that are specified in RS-001. The following is a comparison of these GDCs to the corresponding (or nearly corresponding) GDCs of the PTN design basis. The comparison is made in order to give the licensee's LAR, which is evaluated according to the PTN design basis, a reference to RS-001, and to evaluations of newer plant designs.

GDCs that are preceded by "PTN" are GDCs in the PTN design basis. GDCs that are preceded by "d" are draft GDCs that were available in 1967; but not included in the PTN design basis.

GDC-4, "Environmental and dynamic effects design bases": Structures, systems, and components important to safety shall be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, including loss-of-coolant accidents. These structures, systems, and components shall be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids, that may result from equipment failures and from events and conditions outside the nuclear power unit. However, dynamic effects associated with postulated pipe ruptures in nuclear power units may be excluded from the design basis when analyses reviewed and approved by the Commission demonstrate that the probability of fluid system piping rupture is extremely low under conditions consistent with the design basis for the piping.

For primary loop piping, FPL commits to meeting GDC 4, in lieu of PTN GDC-40 (below):

PTN GDC-40, "Missile Protection": Adequate protection for those engineered safety features, the failure of which could cause an undue risk to the health and safety of the public, shall be provided against dynamic effects and missiles that might result from plant equipment failure.
GDC-5, "Sharing of structures, systems, and components": Structures, systems, and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units. *PTN GDC-4, "Sharing of Systems": Reactor facilities may share systems or components if it can be shown that such sharing will not result in undue risk to the health and safety of the public.*
GDC-10, "Reactor design": The reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded during any condition of normal operation, including the effects of anticipated operational occurrences. *PTN GDC-6, "Reactor Core Design": The reactor core with its related controls and protection systems shall be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which have been stipulated and justified. The core and related auxiliary system designs shall provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated.*
GDC-5, "Reactor coolant system design": The reactor coolant system and associated auxiliary, control, and protection systems shall be designed with sufficient margin to assure that the design conditions of the reactor coolant pressure boundary are not exceeded during any condition of normal operation, including anticipated operational occurrences. *There is no PTN GDC that directly corresponds to GDC 15. PTN GDC-34, "Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention," requires that, "Consideration is given to the design and construction of the reactor pressure vessel in accordance with applicable codes, …(and) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes."*

GDC-19, “Control room”: A control room shall be provided from which actions can be taken to operate the nuclear power unit safely under normal conditions and to maintain it in a safe condition under accident conditions, including loss-of-coolant accidents. Adequate radiation protection shall 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. Equipment at appropriate locations outside the control room shall be provided (1) with a design capability for prompt hot shutdown of the reactor, including necessary instrumentation and controls to maintain the unit in a safe condition during hot shutdown, and (2) with a potential capability for subsequent cold shutdown of the reactor through the use of suitable procedures.

Applicants for and holders of construction permits and operating licenses under this part who apply on or after January 10, 1997, applicants for design certifications under part 52 of this chapter who apply on or after January 10, 1997, applicants for and holders of combined licenses under part 52 of this chapter who do not reference a standard design certification, or holders of operating licenses using an alternative source term under Sec. 50.67, shall meet the requirements of this criterion, except that with regard to control room access and occupancy, adequate radiation protection shall be provided to ensure that radiation exposures shall not exceed 0.05 Sv (5 rem) total effective dose equivalent (TEDE) as defined in Sec. 50.2 for the duration of the accident.

PTN GDC-11 was replaced by FPL commitment to GDC-19:

> *PTN GDC-11, “Control Room”: The facility shall be provided with a control room from which actions to maintain safe operational status of the plant can be controlled. Adequate radiation protection shall be provided to permit access, even under accident conditions, to equipment in the control room or other areas as necessary to shut down and maintain safe control of the facility without excessive radiation exposures of personnel.*

GDC-20, “Protection system functions”: The protection system shall be designed (1) to initiate automatically the operation of appropriate systems including the reactivity control systems, to assure that specified acceptable fuel design limits are not exceeded as a result of anticipated operational occurrences and (2) to sense accident conditions and to initiate the operation of systems and components important to safety.

PTN GDC-14,” Core Protection System”: Core protection systems, together with associated equipment, shall be designed to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

PTN GDC-15, “Engineered Safety Features Protection Systems”: Protection systems shall be provided for sensing accident situations and initiating the operation of necessary engineered safety features.

GDC-25, “Protection system requirements for reactivity control malfunctions”: The protection system shall be designed to assure that specified acceptable fuel design limits are not exceeded for any single malfunction of the reactivity control systems, such as accidental withdrawal (not ejection or dropout) of control rods. *PTN GDC-31, “Reactivity Control System Malfunction”: The reactor protection systems shall be capable of protecting against any single malfunction of the reactivity control system, such as unplanned continuous withdrawal (not ejection or dropout) of a control rod, by limiting reactivity transients to avoid exceeding acceptable fuel damage limits.*
GDC-26, “Reactivity control system redundancy and capability”: Two independent reactivity control systems of different design principles shall be provided. One of the systems shall use control rods, preferably including a positive means for inserting the rods, and shall be capable of reliably controlling reactivity changes to assure that under conditions of normal operation, including anticipated operational occurrences, and with appropriate margin for malfunctions such as stuck rods, specified acceptable fuel design limits are not exceeded. The second reactivity control system shall be capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes (including xenon burnout) to assure acceptable fuel design limits are not exceeded. One of the systems shall be capable of holding the reactor core subcritical under cold conditions. *PTN GDC-27, “Redundancy of Reactivity Control”: Two independent reactivity control systems, preferably of different principles, shall be provided.* *PTN GDC-28, “Reactivity Hot Shutdown Capability”: The reactivity control systems provided shall be capable of making and holding the core subcritical from any hot standby or hot operating condition.* *PTN GDC-29, “Reactivity Shutdown Capability”: One of the reactivity control systems provided shall be capable of making the core subcritical under any anticipated operating condition (including anticipated operational transients) sufficiently fast to prevent exceeding acceptable fuel damage limits. Shutdown margin should assure subcriticality with the most reactive control rod fully withdrawn.*
GDC-27, “Combined reactivity control systems capability”: The reactivity control systems shall be designed to have a combined capability, in conjunction with poison addition by the emergency core cooling system, of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained. *PTN GDC-30, “Reactivity Holddown Capability”: The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public.*

GDC-28, “Reactivity limits”: The reactivity control systems shall be designed with appropriate limits on the potential amount and rate of reactivity increase to assure that the effects of postulated reactivity accidents can neither (1) result in damage to the reactor coolant pressure boundary greater than limited local yielding nor (2) sufficiently disturb the core, its support structures or other reactor pressure vessel internals to impair significantly the capability to cool the core. These postulated reactivity accidents shall include consideration of rod ejection (unless prevented by positive means), rod dropout, steam line rupture, changes in reactor coolant temperature and pressure, and cold water addition. *PTN GDC-32, “Maximum Reactivity Worth of Control”: Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core.*
GDC-29, “Protection against anticipated operational occurrences”: The protection and reactivity control systems shall be designed to assure an extremely high probability of accomplishing their safety functions in the event of anticipated operational occurrences. *There is no PTN GDC that directly corresponds to GDC 29.*
GDC-31, “Fracture prevention of reactor coolant pressure boundary”: The reactor coolant pressure boundary shall be designed with sufficient margin to assure that when stressed under operating, maintenance, testing, and postulated accident conditions (1) the boundary behaves in a nonbrittle manner and (2) the probability of rapidly propagating fracture is minimized. The design shall reflect consideration of service temperatures and other conditions of the boundary material under operating, maintenance, testing, and postulated accident conditions and the uncertainties in determining (1) material properties, (2) the effects of irradiation on material properties, (3) residual, steady state and transient stresses, and (4) size of flaws. *PTN GDC-34, “Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention”: The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failure. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes.*

GDC-33, “Reactor coolant makeup”: A system to supply reactor coolant makeup for protection against small breaks in the reactor coolant pressure boundary shall be provided. The system safety function shall be to assure that specified acceptable fuel design limits are not exceeded as a result of reactor coolant loss due to leakage from the reactor coolant pressure boundary and rupture of small piping or other small components which are part of the boundary. The system shall be designed to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished using the piping, pumps, and valves used to maintain coolant inventory during normal reactor operation. *There is no PTN GDC that directly corresponds to GDC-33.*
GDC-34, “Residual heat removal”: A system to remove residual heat shall be provided. The system safety function shall be to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits and the design conditions of the reactor coolant pressure boundary are not exceeded. Suitable redundancy in components and features, and suitable interconnections, leak detection, and isolation capabilities shall be provided to assure that for onsite electric power system operation (assuming offsite power is not available) and for offsite electric power system operation (assuming onsite power is not available) the system safety function can be accomplished, assuming a single failure. *There is no PTN GDC that directly corresponds to GDC 34.*

GDC-35, “Emergency core cooling”: A system to provide abundant emergency core cooling shall be provided. The system safety function shall be to transfer heat from the reactor core following any loss of reactor coolant at a rate such that (1) fuel and clad damage that could interfere with continued effective core cooling is prevented and (2) clad metal-water reaction is limited to negligible amounts.

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

PTN GDC-37, “Engineered Safety Features Basis for Design”: Engineered safety features shall be provided in the facility to back up the safety provided by the core design, the reactor coolant pressure boundary, and their protection systems. Such engineered safety features shall be designed to cope with any size reactor coolant piping break up to and including the equivalent of a circumferential rupture of any pipe in that boundary, assuming unobstructed discharge from both ends.

PTN GDC-38, “Reliability and Testability of Engineered Safety Features”: All engineered safety features shall be designed to provide such functional reliability and ready testability as is necessary to avoid undue risk to the health and safety of the public.

PTN GDC-39, “Emergency Power for Engineered Safety Features”: Alternate power systems shall be provided and designed with adequate independency, redundancy, capacity and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite power system and the offsite power system shall each, independently, provide this capacity assuming a failure of a single active component in each system.

PTN GDC-41, “Engineered Safety Features Performance Capability”: Engineered safety features, such as the emergency core cooling system and the containment heat removal system, shall provide sufficient performance capability to accommodate the failure of any single active component without resulting in undue risk to the health and safety of the public.

PTN GDC-42, Engineered Safety Features Components Capability: Engineered safety features shall be designed so that the capability of these features to perform their required function is not impaired by the effects of a loss-of-coolant accident to the extent of causing undue risk to the health and safety of the public.

PTN GDC-43, “Accident Aggravation Prevention”: Protection against any action of the engineered safety features which would accentuate significantly the adverse after-effects of a loss of normal cooling shall be provided.

PTN GDC-44, “Emergency Core Cooling System Capability”: An emergency core cooling system with the capability for accomplishing adequate emergency core cooling shall be provided. This core cooling system and the core shall be designed to prevent fuel and clad damage that would interfere with the emergency core cooling function and to limit the clad metal-water reaction to acceptable amounts for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such emergency core cooling system shall be evaluated conservatively in each area of uncertainty.

GDC-54, "Piping systems penetrating containment": Piping systems penetrating primary reactor containment shall be provided with leak detection, isolation, and containment capabilities having redundancy, reliability, and performance capabilities which reflect the importance to safety of isolating these piping systems. Such piping systems shall be designed with a capability to test periodically the operability of the isolation valves and associated apparatus and to determine if valve leakage is within acceptable limits. *There is no PTN GDC that directly corresponds to GDC 54. There is a draft GDC, from 1967, that is not in the PTN design basis (dGDC-53, below):* *dGDC-53, "Containment isolation valves" (Category A): Penetrations that require closure for the containment function shall be protected by redundant valving and associated apparatus.*
GDC-62, "Prevention of criticality in fuel storage and handling": Criticality in the fuel storage and handling system shall be prevented by physical systems or processes, preferably by use of geometrically safe configurations. *PTN GDC-66, "Prevention of Fuel Storage Criticality": Criticality in the new and spent fuel storage pits shall be prevented by physical systems or processes. Such means as geometrically safe configurations shall be emphasized over procedural controls.*

This table is used, in the staff's regulatory evaluations of the individual accident and transient analyses that follow, to provide perspective and boundary conditions for the staff's technical evaluations and conclusions.

TCD Impact on Accident and Transient Analyses – Summary

A summary of the licensee's assessment of the TCD impact on the accident and transient analyses is provided in the below table. In most cases, the transients were unaffected simply because the event is more severe with lower fuel temperatures, or because the analysis treats fuel parameters in a sufficiently conservative manner as to be unaffected by the impact of TCD.

In some cases, the licensee explicitly analyzed the events to include the effects of TCD. Where this is the case, the below table indicates so. The analyses, and updated results, are discussed in the appropriate section of this Safety Evaluation for the postulated event.

TCD Disposition for Postulated Events

2.8.5.1	Decrease in Feedwater Temperature	Bounded by other Events
	Increase in Feedwater Flow	Min. Fuel Temperature
	Increase in Steam Flow	Min. Fuel Temperature
	Inadvertent Opening of a Steam Generator Relief or Safety Valve	Bounded by other Events
	Main Steam Line Breaks	Min. Fuel Temperature
2.8.5.2	Loss of Load/Turbine Trip DNBR	Max. Fuel Temperature
	Loss of Load/Turbine Trip RCS Pressure	Max. Fuel Temperature
	Loss of Load/Turbine Trip MSS Pressure	Max. Fuel Temperature
	Loss of all AC Power	Max. Fuel Temperature
	Loss of Normal Feedwater Flow	Max. Fuel Temperature
	Feedwater Line Breaks	Max. Fuel Temperature
2.8.5.3	Loss of Forced Reactor Coolant Flow	Min. Fuel Temperature
	RCP Rotor Seizure/Shaft Break - DNB	Min. Fuel Temperature
	RCP Rotor Seizure/Shaft Break - PCT	Explicitly Analyzed
2.8.5.4	RCCA Withdrawal - Subcritical	Explicitly Analyzed
	RCCA Withdrawal - At Power DNBR	Min. Fuel Temperature
	RCCA Withdrawal - At Power Pressure	Explicitly Analyzed
	RCCA Drop	Min. Fuel Temperature
	RCCA Bank Drop	Min. Fuel Temperature
	Satically Misaligned RCCA	Min. Fuel Temperature
	Inadvertent Startup of Inactive Loop	Not Analyzed
	CVCS Malfunction - Boron Dilution	Unaffected
	Rod Ejection Accident	Explicitly Analyzed
2.8.5.5	Inadvertent ECCS Actuation	Not Analyzed
	CVCS Malfunction - Mass Addition	Unaffected
2.8.5.6	Inadvertent Opening of a Pressurizer Power Operated Relief Valve	Min. Fuel Temperature
	Steam Generator Tube Rupture	Analysis Uses Bounding Inputs
	Small Break Loss of Coolant Accident	Low PCT; Unaffected
	Large Break Loss of Coolant Accident	Explicitly Analyzed
	Post-LOCA Long Term Core Cooling	Decay Heat-Driven; Unaffected
2.8.5.7	Anticipated Transients Without Scram	Min. Fuel Temperature

If the event is bounded by other events in the licensing basis, then the licensee did not perform an evaluation of the impact that TCD would have on the event, but rather concluded that TCD would not affect the event. The staff finds this acceptable, because the licensee addressed TCD for the bounding events.

If the analysis for the event assumes that the minimum fuel temperature delivers a more limiting result, the licensee concluded that the postulated event would be unaffected by TCD. Since the effect of TCD is to elevate fuel temperatures, the staff agrees that the minimum fuel temperature events are unaffected by TCD and finds the disposition acceptable.

The licensee stated that the RETRAN fuel rod model uses a higher initial fuel temperature than the actual values predicted for PTN using PAD. The licensee also stated that RETRAN introduces two additional conservatisms because it models a uniform initial fuel temperature, and because even fresh fuel is modeled at an elevated fuel temperature. Therefore, the RETRAN maximum fuel temperature events provide adequate margin to address TCD. The staff finds the licensee’s disposition for the maximum fuel temperature events acceptable, since the RETRAN fuel rod model used initial fuel rod temperatures that bounded the effects of the TCD correction.

2.8.5.1 Increase in Heat Removal by the Secondary System

2.8.5.1.1 Decrease in Feedwater Temperature and Increase in Feedwater Flow

Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature which 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) The postulated initial and long-term core and reactor conditions,

(2) The methods of thermal and hydraulic analyses,

(3) The sequence of events,

(4) The assumed reactions of reactor system components,

(5) The functional and operational characteristics of the RPS,

(6) Operator actions, and

(7) The results of the transient analyses.

The NRC’s acceptance criteria are based on:

(1) GDC-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. GDC-10 corresponds to PTN GDC-6, “Reactor Core Design.” See Section 2.8.5 for further information;

(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. GDC-15 has no directly corresponding GDC in the PTN design basis;

(3) GDC-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded during any condition of normal operation, including AOOs. GDC-20 corresponds to PTN GDC-14, “Core Protection System”; 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. GDC-26 corresponds to PTN GDC-27, “Redundancy of Reactivity Control,” PTN GDC-28, “Reactivity Hot Shutdown Capability,” and PTN GDC-29, “Reactivity Shutdown Capability.”

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

As anticipated operational occurrences (AOOs), each of the events that make up the Increase in heat removal by the secondary system category is required to meet the three AOO analysis acceptance criteria:

(1) Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design values in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

(2) Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit.

(3) An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

Specific review criteria are contained in SRP Section 15.1.1 4 and other guidance is provided in Matrix 8 of RS-001. The staff’s application of this guidance takes into account the specific GDCs to which the PTN units were designed and licensed.

<u>NRC Technical Evaluation</u>

Increase in Heat Removal by the secondary system encompasses four AOOs: (1) decrease in feedwater temperature, (2) increase in feedwater flow, (3) increase in steam flow, and (4) inadvertent opening of a steam generator relief or safety valve. Each of these AOOs is evaluated separately.

A change in SG feedwater conditions that results in an increase in feedwater flow or a decrease in feedwater temperature could result in excessive heat removal from the RCS. Such changes

in feedwater flow or feedwater temperature are a result of a failure of a feedwater control valve or feedwater bypass valve, failure in the feedwater control system, or operator error. Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to an increase in power level. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. The reactor protection system (RPS) and safety systems are actuated to mitigate the transient.

The acceptance criteria for AOOs require that the SAFDLs are not exceeded, and that pressure in the RCS and main steam system (MSS) are maintained below 110 percent of the design pressures. Demonstrating that the SAFDLs are not exceeded, and fuel cladding integrity is maintained, is accomplished by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains greater than the 95/95 DNBR safety analysis limit in the limiting fuel rods. Specific review criteria are found in SRP Section 15.1.1-4.

Decrease in Feedwater Temperature

If a low-pressure feedwater heater bypass valve were to be opened, then the reduction in feedwater temperature would increase the thermal load on the primary system by no more than the increase that would be caused by another AOO, the increase in steam flow event, which is defined as a step-load increase of 10 percent from full load. The analysis of the increase in secondary steam flow event, described in LR Section 2.8.5.1.1.2.3, indicates that the resulting decrease in primary coolant temperature is greater than the reduction that would be caused by the feedwater temperature reduction event. Therefore, the staff accepts the licensee's analysis of the increase in steam flow event as an effective evaluation of the decrease in feedwater temperature event.

Increase in Feedwater Flow

An increase in feedwater flow causes moderator temperature to drop, and this temperature reduction, in the presence of a negative moderator temperature coefficient, can cause core power to increase to a level that is greater than full rated power. A timely reactor trip, from high neutron flux, OTΔT, or overpower (OP) ΔT would prevent the SAFDLs from being exceeded (i.e., the minimum DNBR does not drop below the safety limit value).

The increase in feedwater flow would cause steam generator water level to rise. If it reaches the steam generator high-high level signal, then the turbine will be tripped and the feedwater flow would be ended.

The increase in feedwater flow event analysis is based upon the assumption that one feedwater control valve is inadvertently opened. The analysis is considered for full and zero power conditions, with and without automatic rod control. All cases are analyzed with a highly negative moderator temperature coefficient that would be typical of end of life (EOL) core conditions. The staff agrees that the most limiting case is the increase in feedwater flow event that is assumed to occur at hot full power (HFP) without the availability of automatic rod control.

The limiting increase in feedwater flow case was analyzed using the RETRAN code, which has been approved by the NRC for licensing applications.[107] The RETRAN code simulates a multi-loop RCS, including core neutron kinetics, steam generators, and the main feedwater system. RETRAN calculates transient values for key parameters, like coolant temperatures, pressure, power level and DNBR (for the HFP cases).

The increase in feedwater flow event ends when the turbine is tripped high-high steam generator water level. The high-high steam generator water level signal also initiates automatic closure of all feedwater control and isolation valves, closure of all feedwater bypass valves, and trips the feedwater pumps.

The turbine trip will also trip the reactor; but this reactor trip should not be credited in FSAR accident analyses, since it originates in the nonseismically qualified turbine hall. The analysis results, summarized in LR Table 2.8.5.1.1.2.2-1, indicate that the reactor trip is demanded by the turbine trip. The reactor trip occurs (i.e., the rods begin to drop into the core) at 42.9 seconds, exactly two seconds after the turbine is tripped. The staff does not accept a reactor trip that is initiated by a turbine trip, as a safety grade reactor trip sequence.

However, the same table indicates that the minimum DNBR is reached at 42.3 seconds, or 0.6 seconds before the rods begin to drop into the core. The DNBR, therefore, begins to rise after the addition of cold feedwater is terminated by the turbine trip sequence, not by the power reduction that results from the reactor trip. The staff concludes that the time and source of the reactor trip signal, in this analysis, does not determine the time or value of the minimum DNBR. The staff accepts the analysis result (i.e., that the minimum DNBR remains greater than the DNBR safety limit value throughout the transient).

The staff asked the licensee, in an RAI, if there are any other analyses in which the reactor trip is assumed to be initiated by the turbine trip. The licensee replied there are not.[108] The reactor trip signal that derives from the turbine trip is not accepted, by the staff, as a safety grade signal that can be credited in accident and transient analyses.

If the reactor is not assumed to be tripped directly from the turbine trip, then the termination of feedwater, which would result from a turbine trip, will transform the event into a loss of feedwater. Unlike the increase in feedwater flow event, the loss of feedwater event causes the RCS temperatures to increase. The loss of feedwater would eventually lead to a reactor trip on a low-low steam generator level signal. The analysis results of a loss of feedwater event are reported in LR Section 2.8.5.2.3. They indicate that the RCPB pressure limit will be not exceeded, and that the event will not develop into a more serious event. Therefore, the two event analyses, together, show that all of the AOO analysis acceptance criteria are satisfied.

[107] Huegel, D.S., et al., Westinghouse Electric Company, "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," WCAP-14882-P-A, April, 1999. ML093421329.
[108] ML11221A227.

2.8.5.1.2 Increase in Steam Flow; Inadvertent Opening of a Steam Generator Relief Valve

Regulatory Evaluation

The regulatory evaluation for the Increase in steam flow and the inadvertent opening of a steam generator relief valve events is conducted according to the same criteria as those applied for the decrease in feedwater temperature and increase in feedwater flow events (see Section 2.8.5.1.1).

NRC Technical Evaluation

Increase in Steam Flow

The increase in steam flow event, or excessive load increase event, is considered as a 10 percent step-load increase at HFP. The reactor control system is designed to tolerate a 10 percent step-load increase and/or a 5 percent per minute ramp-load increase without leading to a reactor trip. If the load increase exceeds these levels, then the reactor protection system could demand a reactor trip, and thereby prevent the SAFDLs from being exceeded.

This event could be caused by an operator error, or an equipment malfunction in the steam dump control or turbine speed control. During power operation, for example, steam bypass to the condenser could be initiated by high reactor coolant temperature.

The excessive load increase event is analyzed using the RETRAN[109] computer code. The RETRAN code simulates the reactor coolant system, neutron kinetics in the core, pressurizer, pressurizer relief and safety valves, steam generators, main feedwater system and main steam safety valves. The code calculates transient values for key plant parameters, such as steam generator shell-side mass, pressurizer water volume, reactor coolant average temperature, reactor coolant system pressure, steam generator pressure, and DNBR.

The analysis results indicate that the plant design can tolerate a 10 percent step-load increase. All the analysis cases showed that plant conditions stabilized at the higher power level demanded by the increase in steam flow (i.e., plant conditions did not reach a state that would require the reactor to trip). Therefore, the safety analysis limit values for minimum DNBR and peak linear heat generation are not exceeded, and the calculated pressurizer water volume transients do not predict a water-solid pressurizer, at any time. Therefore, this AOO would not lead to a more serious plant condition.

Based upon the analysis results, provided by the licensee, the staff concludes that the proposed power uprate is acceptable with respect to the increase in steam flow event.

Inadvertent Opening of a Steam Generator Relief Valve

The inadvertent opening of a steam generator relief valve, an AOO, would result in a steam release rate that is limited by the capacity of the relief valve. A conservative analysis of this

[109] ML093421329

event would consider the capacity of the largest valve in the main steam system. This would be about 10 percent of nominal steam flow.

The licensee does not present an analysis of the inadvertent opening of a steam generator relief valve. Instead, the licensee observes that the resulting steam release, from an inadvertent opening of a steam generator relief valve, would be much lower than that produced by the double-ended steamline rupture. The double-ended steamline rupture is classified as an ANS Condition IV event. However, both events are evaluated against the AOO acceptance criteria. The licensee compares the two steam release rates, and concludes that the double-ended steamline rupture is the limiting case. Therefore, an analysis of the inadvertent opening of a steam generator relief valve is not necessary.

The staff does not agree that a comparison, between the two events, can be made strictly on the basis of steam release rate. The comparison is complicated by the fact that the differences in cooldown and depressurization rates, between the two events, would elicit different responses from the reactor protection system (RPS).

The inadvertent opening of a steam generator relief valve, for instance, would not produce the high steam release rate that is necessary to actuate steam line isolation. For steam line isolation, the PTN RPS logic requires a high steam flow condition, coincident with either low RCS average temperature, or with low steam generator pressure. Alternatively, steam line isolation could be actuated by high-high containment pressure. In this case, the high-high containment pressure condition would not be reached, since the steam generator relief valves are located outside containment. Therefore, steam line isolation could not be expected to occur during an inadvertent opening of a steam generator relief valve. Without steamline isolation, only the nonreturn valve in the affected steamline would prevent reverse flow from exiting through the open steam generator relief valve, and blowing down the unaffected steam generators. Similarly, the high steam flow condition could not be relied upon to actuate safety injection (SI). For an inadvertent opening of a steam generator relief valve, SI would eventually be actuated by a low pressurizer pressure condition.

The double-ended steamline rupture, however, would quickly actuate the SI system, and steam line isolation. Since each steam line contains an isolation valve and a nonreturn valve in series, only one steam generator will blow dry. When the steam generator is empty, the accident is over. If the steam lines are not isolated (e.g., due to an inadvertent opening of a steam generator relief valve), then they would have to be isolated manually, to prevent all the steam generators from drying out. A conservatively short period, available for manual action, can be estimated by assuming that an open steam system valve would release steam at a rate of 247 lbs/sec, and that each of PTN's three steam generators contains a shell-side inventory of 150,000 lbs of water and steam. Under these assumed conditions, there would be more than 30 minutes available, for the operator to isolate the steam lines, and maintain some steam generator shell-side inventory for decay heat removal. Reducing the steam release rate, as the steam generators depressurize, would considerably lengthen this time period.

If a steam generator relief valve were to be inadvertently opened, and no protective actions (e.g., SI or steam line isolation) were triggered, then the core could be expected to return to critical and generate power at a level that would match the steam release rate. This power generation/steam flow match would continue until the manual remedies are taken.

However, the peak power level that would be attained would be relatively low. The peak core heat flux, predicted by the double-ended steamline rupture analysis, as reported in LR Section 2.8.5.1.2, is greater than 13 percent of the nominal power rating. This is higher than the highest heat flux that could be produced by the inadvertent opening of a steam generator relief valve. There is no valve in the main steam system that could release steam at a rate that could match this 13 per cent value. Therefore, the inadvertent opening of a steam generator relief could not produce a peak heat flux that is higher than that produced by the double-ended steamline rupture, even if no mitigation actions (e.g., SI or steam line isolation) are actuated.

The staff does not agree that one event – a fast, short cooldown that quickly actuates steam line isolation – will necessarily bound the other event: a long, slow cooldown that does not actuate steamline isolation. For the PTN units, however, the staff concludes that the double-ended steamline rupture bounds the inadvertent opening of a steam generator relief valve. The results of the major rupture of a main steam pipe analyses (LR Section 2.8.5.1.2) indicate that the SAFDLs are not exceeded. This would be true, too, for the inadvertent opening of a steam generator relief valve. Therefore, the DNB design basis is satisfied for the Inadvertent Opening of a Steam Generator Relief Valve.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's analyses of the excess heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level, and that the 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 that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on these considerations, the NRC staff concludes that the plant will continue to meet the requirements of PTN GDCs 6, 14, 27, 28, and 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the events stated.

2.8.5.1.3 Steam System Piping Failures Inside and Outside Containment

<u>Regulatory Evaluation</u>

The main steam line break (MSLB) is classified as an ANS Condition IV event. According to RS-001, the NRC staff's acceptance criteria for Condition IV MSLB analyses are based upon GDCs 27, 28, 31, and 35. The PTN MSLB analyses, like the MSLB analyses of other Westinghouse-designed plants, indicate that AOO (Condition II) acceptance criteria are satisfied. Therefore, the staff has applied the AOO acceptance criteria and the PTN-equivalent GDCs for AOOs, to its evaluation of the PTN MSLB analyses, in order to determine Condition IV criteria are met. Meeting the AOO criteria demonstrates that the application of these, more restrictive criteria, permits a more appropriate, more relevant evaluation, than the criteria specified in RS-001. The staff's approach in this regulatory evaluation does not alter the PTN licensing basis. The MSLB classification, as a Condition IV event, remains unchanged.

The staff's acceptance criteria for the PTN MSLB events are based upon the three ANS acceptance criteria for Condition II events, and on PTN GDCs 6, 14, 27, 28, and 29.

NRC Technical Evaluation

The steam release from an MSLB removes energy from the RCS (and core), and causes a reduction of reactor coolant temperature and pressure. In the presence of a negative moderator temperature coefficient (MTC), the cooldown effectively inserts positive reactivity which could overcome the post-trip core shutdown margin. If the most reactive rod cluster control assembly (RCCA) is assumed to be stuck in its fully withdrawn position, after a reactor trip, it is likely that the core will become critical and return to power. A return to power, with a rod stuck out of the core, could result in DNB, in the region of the stuck rod, due to high, local power peaking factors. The core is ultimately shut down by the addition of boric acid by the ECCS (high head safety injection (SI) and accumulators). Automatic steam line isolation prevents the blowdown of more than one steam generator. The MSLB is essentially over (i.e., the cooldown is ended) when the unisolated SG blows dry.

The MSLB is analyzed at hot full power (HFP) and at hot zero power (HZP). Specifically, the HFP case is analyzed at the EPU power level, and the HZP case is analyzed in Mode 2 conditions. The HZP case is the limiting case with respect to core cooldown and DNB. It relies upon the ECCS and steam line isolation for mitigation. The HFP case is analyzed to demonstrate that fuel damage does not occur due to DNB or fuel centerline melting. It relies upon the reactor trip, due to high neutron flux, overpower ΔT, or to an SI signal from low steam line pressure coincident with high steam flow. The HFP case, which has been added to the licensing basis for this EPU application, is analyzed until the reactor trip occurs. The HZP case analysis applies after the reactor trip occurs.

For the EPU analyses, the RETRAN computer code[110] is used to predict the plant transient conditions following a MSLB. The code computes pertinent variables, including the core power, RCS temperature and pressure. This is followed by a core analysis, performed using the ANC code,[111] to verify the RETRAN reactivity feedback predictions. Statepoints consisting of nuclear power, RCS loop inlet temperatures, pressure, and core flow, along with radial and axial power distributions calculated by ANC, are then input to VIPRE,[112] which uses a detailed thermal and hydraulic model to calculate the minimum DNBR.

For the EPU analyses, RETRAN replaces LOFTRAN, and VIPRE replaces THINC. All of these computer codes are accepted by the staff for licensing applications.

The HZP MSLB analyses are based upon the complete severance of a main steam line, which opens an effective break area of 1.388 ft^2. This is the throat area of the integral flow restrictors that are installed in each of the steam pipes carry steam from the Westinghouse Model 44F

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[110] WCAP-14882-P-A (Proprietary) and WCAP-15234-A (Nonproprietary), "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," Huegel, D. S., et al., April 1999 and May 1999.
[111] WCAP-10965-P-A (Proprietary), ANC: A Westinghouse Advanced Nodal Computer Code, Davidson, S. L. (Ed.), et al., September 1986.
[112] WCAP-14565-P-A (Proprietary) and WCAP-15306-NP-A (Non-proprietary), VIPRE-01, Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis, Sung, Y. X. et al., October 1999.

steam generators of the PTN units. The steam break flow chokes at the flow restrictor. This is the largest possible break area, and it leads to the most severe core cooldown.

A smaller break size, 0.65 ft^2, is assumed for the HFP MSLB cases. The licensee has determined that the smaller break sizes move the plant operating conditions to match higher steam loads, which do not require a reactor trip. The large break sizes, up to and including the 1.388 ft^2 break; result in a reactor trip from the low steam generator pressure coincident with high steam flow SI signal, very early in the transient. This relatively prompt reactor trip effectively limits the consequences. It is conservative to reduce the break size to an area that allows the plant to generate a power that is high enough to require a reactor trip from the OPΔT trip signal. The limiting HFP MSLB break size has been found to be 0.65 ft^2. This is the largest break size that leads to a reactor trip on an OPΔT trip signal.

The results of the MSLB analyses, at HFP and HZP, are summarized below:

MSLB	HFP (0.65 ft^2)	HZP (1.388 ft^2)
Minimum DNBR/limit	1.84/[[ ]]	1.328/1.18
Peak linear heat generation rate (kW/ft)/limit	[[ ]]/[[ ]]	[[ ]]/[[ ]]

The results indicate that the AOO acceptance criteria are satisfied. The PTN MSLB is not predicted to result in any fuel damage due to DNB or fuel centerline melting. The PTN MSLB does not challenge the RCPB and MSS pressure limits, since the MSLB causes a depressurization of the RCS and MSS.

TCD Supplement to 2.8.5.1.3

The licensee evaluated the main steamline breaks for the effects of TCD. Because the main steamline breaks use minimum fuel temperature conditions, the transient results are largely unaffected. The steam line breaks are, however, analyzed for fuel melt. In order to ensure that the fuel melt results remain valid and bounding when corrected for TCD, new, burnup-dependent kW/ft limits are imposed on the fuel. The limits were verified by the staff using FRAPCON calculations, as discussed in Section 2.8.1 of this SE. Adherence to the limits will be ensured through the NRC-accepted RSAC process. The staff finds this approach to accounting for TCD acceptable, since it will ensure that the existing analyses remain bounding in consideration of the effects of TCD.

Conclusion

The NRC staff has reviewed the licensee's analyses of the steam system piping failures inside and outside containment described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB and MSS pressure limits will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of PTN GDCs 6, 14, 27, 28, and 29 following implementation of the

proposed EPU. Therefore, the plant will also meet the PTN equivalents of GDCs 27, 28, 31, and 35. The NRC staff finds the proposed EPU acceptable with respect to Condition IV MSLB event occurring inside and outside containment.

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 transient. 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. GDC-10 corresponds to PTN GDC-6, Reactor Core Design. See Section 2.8.5 for further information.

(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. GDC-15 has no directly corresponding GDC in the PTN design basis.

(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. GDC-26 corresponds to PTN GDC-27, “Redundancy of Reactivity Control,” PTN GDC-28, “Reactivity Hot Shutdown Capability,” and PTN GDC-29, “Reactivity Shutdown Capability.”

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

As AOOs, each of the events that make up the decrease in heat removal by the secondary system category is required to meet the three AOO analysis acceptance criteria:

1. Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design values in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

2. Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit.

3. An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

Specific review criteria are contained in SRP Section 15.2.1-5 and other guidance is provided in Matrix 8 of RS-001.

NRC Technical Evaluation

A major loss of load can result from either a loss-of-external electrical load or from a turbine trip from full power without a direct reactor trip. These events result in a sudden reduction in steam flow. The loss of heat sink can lead to elevated core temperatures, and to a pressurization of the reactor coolant and the main steam systems (MSS).

The NRC staff agrees that the limiting loss of heat sink event is the turbine trip or the loss of condenser vacuum (which leads to a turbine trip). These events are very similar, since their analyses share two key assumptions: no direct reactor trip on turbine trip, and no steam dumping to the condenser (i.e., steam is relieved through the main steam safety valves). For this event, it is expected that the reactor will be tripped by the high pressurizer pressure signal, the low-low steam generator water level signal, the OTΔT signal, or the OPΔT signal.

The licensee analyzed three cases for a complete loss of load from full power at EPU conditions:

1) a minimum departure from nucleate boiling ratio (DNBR) case, assuming automatic pressurizer pressure control; RTDP initial conditions;

2) a maximum MSS pressure case, assuming automatic pressurizer pressure control; STDP initial conditions; and

3) a maximum RCS pressure case, assuming no pressurizer pressure control; STDP initial conditions

Case (1) is designed to yield the lowest DNBR. In this case, the operation of pressurizer sprays and pressurizer power-operated relief valves (PORVs) tends to limit the RCS pressurization, caused by the decrease in heat removal by the secondary system, and this would prevent or delay reaching the high pressurizer pressure condition needed to generate the reactor trip signal on the high pressurizer pressure signal. LR Table 2.8.5.2.1-1 indicates that the reactor trip signal comes from the OTΔT protection logic, which is triggered by a degradation in thermal margin, as measured by DNBR. The RTDP is applied in this analysis.

Case (2) is designed to produce highest main steam system (MSS) pressure. In this case, the operation of pressurizer sprays and PORVs are also assumed, in order to limit the RCS pressurization, and thereby prevent or delay the reactor trip from a high pressurizer pressure condition. This would allow the steam generator shell-side pressure to increase to a higher level. The reactor is tripped by the OTΔT signal; but unlike Case (1), RTDP conditions are not applied in this analysis.

Case (3) is analyzed to evaluate the maximum RCS pressure, and test the relief capacity of the pressurizer safety valves. In Case (3), the operation of pressurizer sprays and PORVs are not assumed. The reactor is tripped by the high pressurizer pressure signal. RTDP assumptions are not applied in this analysis.

The analysis results, from LR Table 2.8.5.2.1-4, are listed below:

Case	EPU Analysis	Safety Analysis Limit
(1) Min DNBR	1.72	[[ ]]
(2) Max MSS Pr	1,197.1 (psia)	1,208.5 (psia)
(3) Max RCS Pr	2,746.6 (psia)	2,748.5 (psia)

The table indicates that the case analyses demonstrate that two of the three AOO analysis acceptance criteria are satisfied. Case (1) addresses fuel cladding integrity. Cases (2) and (3) address the ASME Boiler and Pressure Vessel Code pressure limits. If the ASME Boiler and Pressure Vessel Code pressure limits are met, then it can be inferred that GDC 15 would likely be met, with the understanding that GDC 15, *per se*, has no corresponding criterion in the PTN design basis.

The staff's focus, in this evaluation, is to gain reasonable assurance that the PTN units are adequately protected against MSS overpressure during the limiting AOO (the loss of load). This safety analysis is based upon the assumption that the plant is operating within its technical specification limits when the AOO occurs. The limiting case (e.g., the case with the least margin to overpressure) is reported. The staff concludes that the analysis results (above) show that the loss of load, occurring at full power, would not lead to an overpressure condition.

In order to achieve acceptable results, the licensee revised the lift settings for some of the MSSVs, and proposed a change in the corresponding technical specifications, including the technical specifications for the maximum allowable power levels when one or more safety valves are inoperable (LR Section 3.1.40). The staff simply scaled down the licensee's maximum allowable power levels for operation with one, two, and three inoperable main steam safety valves (MSSVs) by 15 percent, the proposed increase in rated thermal power, and found the scaled power levels to be fairly consistent with the licensee's values. The comparison is depicted in a modified LR Table 2.8.4.2-2, below:

Table 2.8.4.2-2
Maximum Allowable Power Level versus Operable Main Steam Safety Valves

No. of Operable MSSVs per SG	EPU TS Setpoint (% RTP)	NRC-scaled Setpoint (% RTP)	CLB TS Setpoint (% RTP)
3	44	46	53
2	27	29	33
1	10	12	14

The proposed maximum allowable power levels are conservatively lower than the proportionally scaled maximum allowable power levels. The staff also calculated that all the safety valves are

capable of relieving, together, the full nominal steam flow, when the steam generator pressure is elevated to 110 percent of design pressure (1208.5 psia). This implies that the SG pressure would not be expected to exceed 110 percent of design pressure, for power levels below the nominal (EPU) rating. Therefore, the staff finds that the proposed MSSV setpoint changes and TS changes are acceptable.

Satisfaction of the third AOO analysis acceptance criterion is indicated by evaluation of the transient pressurizer water volume. The analysis results indicate that the maximum pressurizer water volume is not high enough to fill the pressurizer to capacity. Therefore, this event could not develop into a more serious event, since water could not be discharged through the PORVs. Therefore, none of the PORVs are predicted to fail the open position, after having discharged water. The peak pressurizer water volume occurs in Case (1). LR Figure 2.8.5.2.1-2 shows that maximum pressurizer water volume is just about ten cubic feet shy of the pressurizer capacity (1,300 cubic feet).

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

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The 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 and MSS pressure limits will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of PTN GDCs 6, 27, 28, and 29 following implementation of the proposed EPU.

2.8.5.2.2 Loss of Non-Emergency AC Power to the Station Auxiliaries

Regulatory Evaluation

The loss of nonemergency ac power event causes a reactor coolant flow coastdown, a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the primary coolant, and a reactor trip.

For the loss of nonemergency ac power event, the staff applies the same criteria (GDCs and AOO analysis acceptance criteria) as those that are applied for the loss of external load/turbine trip event in Section 2.8.5.2.1.

Specific review criteria are contained in SRP Section 15.2.6, and other guidance is provided in Matrix 8 of RS-001.

NRC Technical Evaluation

The loss of nonemergency ac power is defined to be the loss of all power to the station auxiliaries. This could be the result of a complete loss of either the external (offsite) grid or the onsite AC distribution system. This differs from the loss of load event, considered in Section 2.8.5.2.1 because loss of ac power causes all the reactor coolant pumps to trip. The resulting coolant flow coast-down further decreases the rate of heat removal by the secondary system.

The reactor and turbine also trip, and the RCS pressure and temperature increase. The diesel generators start automatically, and provide electric power to the vital loads. Decay heat is removed by the auxiliary feedwater system.

The analysis of a loss of normal feedwater (LONF) event, when it's combined with a loss of non-emergency AC power (LOAC) that is assumed at the time of reactor trip, produces a more severe transient than the simple LOAC. This is due, principally to a longer power-heat sink mismatch, as the reactor trip must wait until the low-low steam generator water level signal is generated. The LONF/LOAC event would, therefore, produce a higher peak pressurizer volume than either the LOAC event or the LONF event. Neither of these events would reach the peak RCS and MSS pressures of the loss of load event. From a purely DNBR perspective, the minimum DNBR produced by either the LONF event or the LOAC event would be higher than the minimum DNBR produced by the total loss of forced flow event, addressed in Section 2.8.5.3.1.

The results of the LONF/LOAC event analysis are shown in LR Tables 2.8.5.2.2-1 and 2.8.5.2.2-2. They indicate that there is sufficient auxiliary feedwater flow to remove all the decay heat by about 33 minutes. By this time, the RCS temperatures and pressurizer water volume begin to decrease. The maximum pressurizer water volume is 114 ft^3 less than the total pressurizer volume of 1,300 ft^3.

The staff notes that Figure 2.8.5.2.2-2, which depicts pressurizer pressure and water volume vs. time, indicates a period in which the pressurizer safety valves are open. This is unusual; but still acceptable, since the pressurizer is not full (i.e., the relief is limited to steam).

The staff agrees that the LONF/LOAC event is more severe than either the LONF or LOAC event, with respect to the pressurizer insurge. The staff also agrees that the LONF/LOAC event would be less severe than the total loss of forced flow event, with respect to protection of the SAFDLs. The LONF and total loss of forced flow event analyses are evaluated in Sections 2.8.5.2.3 and 2.8.5.3.1, respectively.

Conclusion

The staff agrees that the LONF/LOAC event is not the limiting event with respect to protection of the SAFDLs. Satisfaction of the first AOO acceptance criterion (SAFDLs) is addressed in Section 2.8.5.3.1, which presents an evaluation of the total loss of forced flow event.

The NRC staff has reviewed the licensee's analyses of the LONF/LOAC 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 RCPB and MSS 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 PTN GDCs 6, 27, 28, and 29 following implementation of the proposed EPU.

2.8.5.2.3 Loss of Normal Feedwater Flow

Regulatory Evaluation

The loss of normal feedwater (LONF) flow is a loss of heat sink AOO. It causes an increase in RCS temperature and pressure that could challenge the RCPB safety limit, and the SAFDLs. An LONF could be caused by pump failures, valve malfunctions, or by a loss of offsite power (LOOP). This event is mitigated by a reactor trip and by removal of decay heat by the auxiliary feedwater (AFW) system.

For the LONF, the staff applies the same criteria (GDCs and AOO analysis acceptance criteria) as those that are applied for the loss of external load/turbine trip event in Section 2.8.5.2.1.

Specific review criteria are contained in SRP Section 15.2.7 and other guidance is provided in Matrix 8 of RS-001.

NRC Technical Evaluation

The LONF, an AOO, is defined to be the loss of all main feedwater to the three PTN steam generators. The RCS pressure and temperature tend to increase, and the steam generator water level tends to decrease. The reactor and turbine are tripped on steam generator low-low level. Post-trip decay heat is removed by the AFW system. Once the decay heat generation rate falls below the AFW heat removal capacity, the RCS pressure and temperature will tend to decrease. If the single worst failure is assumed to occur, in the AFW system, then the time at which the RCS pressure and temperature begin to decrease could be 30 minutes or more after the time that main feedwater flow is lost.

The LONF event is less severe than the loss of load event, discussed in LR Section 2.8.5.2.1. That is, the LONF event produces a higher minimum DNBR, and lower peak SCS and MSS pressures. The licensee presents an analysis for an LONF case that is designed to produce the highest pressurizer water volume, to demonstrate that the AFW will be capable of removing all the decay heat before the pressurizer can fill, which could cause the event to develop into a more serious, small break LOCA.

Protection is provided by the reactor trip and the actuation of AFW flow. Both are demanded when the low-low steam generator water level setpoint (4 percent NRS) is reached.

The licensee states that the LONF event analysis accounts for temperature and power uncertainties. The initial power level is 2660 megawatts thermal (MWt), which is the nominal

core power rating, 2644 MWt, plus 8 MWt for reactor coolant pump heat, plus 0.3 percent for uncertainty. This is seen in the plots of the analysis results, in LR Figure 2.8.5.2.3-1, which indicate that the initial power level is 100 percent, not 102 percent. This is not considered to be significant enough to affect the overall results and conclusions.

The maximum pressurizer water volume, 1199 ft^3, is more than 100 ft^3 lower than the total pressurizer water volume.

Conclusion

The staff agrees that the LONF event is not the limiting event with respect to protection of the SAFDLs, or the integrity of the RCS or MSS. The loss of load event, discussed in LR Section 2.8.5.2.1, is the limiting event with respect to these measures. The LONF analysis shows that the LONF will not develop into a more serious event, by showing that the pressurizer will not fill and cause water to be discharged through the pressurizer PORVs.

The NRC staff has reviewed the licensee's analysis of the LONF event, and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the RCPB and MSS 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 PTN GDCs 6, 27, 28, and 29 following implementation of the proposed EPU.

2.8.5.2.4 Feedwater System Pipe Breaks Inside and Outside Containment

Regulatory Evaluation

Depending upon the size and location of the break and the plant operating conditions at the time of the break, a feedwater pipe break could cause either a reactor coolant system (RCS) cooldown (by releasing an excessive amount of energy through the break) or an RCS heatup (by reducing feedwater flow to the affected steam generator). Reactor protection and safety systems are available, and actuated to mitigate the event.

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 predicted response of the reactor coolant and auxiliary systems, (5) the functional and operational characteristics of the reactor protection system, (6) operator actions, and (7) the results of the accident analyses.

The feedwater line break (FWLB) is classified as an ANS Condition IV event, or a postulated accident.

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 emergency core cooling system (ECCS), of reliably controlling reactivity changes under postulated accident

conditions, with appropriate margin for stuck rods, thus ensuring that core cooling capability is maintained. The corresponding criterion, in the PTN design basis, is PTN GDC-30, "Reactivity Holddown Capability":

> The reactivity control systems provided shall be capable of making the core subcritical under credible accident conditions with appropriate margins for contingencies and limiting any subsequent return to power such that there will be no undue risk to the health and safety of the public.

(2) GDC-28, insofar as it requires that the reactivity control systems be designed to ensure that the effects of postulated reactivity accidents can neither result in damage to the reactor coolant pressure boundary (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. The corresponding criterion, in the PTN design basis, is PTN GDC-32, "Maximum Reactivity Worth of Control":

> Limits, which include reasonable margin, shall be placed on the maximum reactivity worth of control rods or elements and on rates at which reactivity can be increased to ensure that potential effects of a sudden or large change of reactivity cannot (a) rupture the reactor coolant pressure boundary or (b) disrupt the core, its support structures, or other vessel internals sufficiently to lose capability of cooling the core.

(3) GDC-31, insofar as it requires that the RCPB be designed with sufficient margin to ensure that, under specified conditions, it will behave in a non-brittle manner and the probability of a rapidly propagating fracture is minimized. The corresponding criterion, in the PTN design basis, is PTN GDC-34, "Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention":

> The reactor coolant pressure boundary shall be designed and operated to reduce to an acceptable level the probability of rapidly propagating type failure. Consideration is given (a) to the provisions for control over service temperature and irradiation effects which may require operational restrictions, (b) to the design and construction of the reactor pressure vessel in accordance with applicable codes, including those which establish requirements for absorption of energy within the elastic strain energy range and for absorption of energy by plastic deformation and (c) to the design and construction of reactor coolant pressure boundary piping and equipment in accordance with applicable codes.

(4) GDC-35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling. The corresponding criterion, in the PTN design basis, is PTN GDC-44, "Emergency Core Cooling System Capability":

> An emergency core cooling system (ECCS) with the capability for accomplishing adequate emergency core cooling shall be provided. This core cooling system and the core shall be designed to prevent fuel and clad damage that would interface with the emergency core cooling function and to limit the clad metal-water reaction to acceptable amounts for all sizes of breaks in the reactor coolant piping up to the equivalent of a double-ended rupture of the largest pipe. The performance of such emergency core cooling system shall be evaluated conservatively in each area of uncertainty.

As a postulated accident, the FWLB analysis is also judged according to these criteria:

1. Pressure in the RCS and main steam system should be maintained below acceptable design limits, considering potential brittle as well as ductile failures.

2. Fuel cladding integrity will be maintained if the minimum DNBR remains above the 95/95 DNBR limit. If the minimum DNBR does not meet these limits, then the fuel is assumed to have failed.

3. The release of radioactive material shall not result in offsite doses in excess of the guidelines of 10 CFR Part 100.

4. A postulated accident shall not, by itself, cause a consequential loss of required functions of systems needed to cope with the fault, including those of the RCS and the containment system.

Specific review criteria are contained in the SRP Section 15.2.8 and other guidance is provided in Matrix 8 of RS-001.

The FWLB is not in the PTN licensing basis. The licensee has provided an analysis of the FWLB in response to the staff's request for additional information. This request and response are discussed in the technical evaluation (below).

<u>NRC Technical Evaluation</u>

The FWLB incident is defined as a break in a feedwater pipe that is large enough to prevent the delivery of enough feedwater to maintain shell-side fluid inventory in the steam generators (SGs). If the break is assumed to be located downstream of the feedwater line check valve, then fluid from the SG will be discharged through the break. A break in this location could also prevent the flow of auxiliary feedwater into the affected SG. On the other hand, if the break is assumed to occur in a feedwater line section that is upstream of the check valve, then no flow will be discharged from the SG. The event will be, in effect, a loss of feedwater.

The lack of feedwater delivery can cause RCS temperatures to increase, and the shell side inventory of the faulted SG to drop. This could reduce the amount of water that is available for decay heat removal following a reactor trip. The FWLB event is analyzed to demonstrate the

ability of the AFW system to adequately remove decay heat, and thereby prevent excessive heatup of the RCS.

The staff noted that the PTN EPU application did not contain an analysis of the FWLB. The licensee explained that submittal of a FWLB analysis would not be required, since the FWLB is not in the PTN licensing basis. The staff regards the FWLB to be an important, design basis accident that is directly affected by an increase in rated power level. Therefore, the staff requested the licensee to provide an analysis of the FWLB. By letter dated October 15, 2011,[113] the licensee provided the requested information. The staff's request is based upon the fact that the FWLB is a design basis event. Its analysis results are used to:

(1) determine the performance requirements of the auxiliary feedwater system, as a post-trip decay heat removal system, under the conditions/configuration that would exist following a FWLB,

(2) determine the low steam generator water level reactor trip setpoint,

(3) determine the error allowance, on the low steam generator water level reactor trip setpoint, needed to compensate for the hostile environment that could be created by the break flow from a FWLB occurring inside containment,

(4) verify the plant's capability to establish and maintain natural circulation cooling, following a FWLB, by showing that saturation conditions are not created inside the reactor coolant system, and

(5) show that the core remains covered and that the integrity of the reactor coolant system pressure boundary is maintained during a FWLB (i.e., when there is water relief though the pressurizer safety valves).

The licensee's FWLB analysis is based upon a rupture in the feedwater line between the check valve and the SG. A break in this location opens a path for the discharge of fluid from the SG, and for the spilling of FW before it can reach the SG. The loss of SG shell side inventory eventually leads to a reactor trip and AFW actuation on low-low SG water level. In the RCS, the FWLB causes an increase in the average reactor coolant temperature, a surge of water into the pressurizer, and an increase in pressure. In the MSS, the reduction/loss of heat sink inventory causes an increase in pressure. No credit is taken for the secondary-side, nonsafety-related power-operated relief valves or atmospheric steam dump valves. Steam is relieved through the SG safety valves, and continues until the RCS heatup ends, when the decay heat generation rate declines to below the heat removal capability of the AFW system. Then, the RCS temperature, pressure, and the pressurizer water level begin to decrease.

During the RCS heatup period, it is possible to lose the RCS subcooling margin. The FWLB analysis demonstrates that the RCS subcooling margin is maintained until the AFW system can adequately cool the RCS and MSS. The single worst failure is assumed to occur in the AFW system.

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[113] ML11292A032

The FWLB transient was analyzed with NRC-approved RETRAN computer code. The code simulates neutron kinetics in the core, the RCS, a pressurizer, pressurizer safety valves, three SGs, and SG safety valves. The code computes pertinent plant variables, including RCS and MSS temperatures, pressures, and power level.

The principal objective of the FWLB analysis is to demonstrate that, under EPU conditions, there is sufficient decay heat removal capability in the AFW system to prevent saturation conditions from developing in the PTN RCS. This includes modeling the effect of the worst single failure in the AFW system to minimize the AFW flow delivered to the intact SGs. The largest double-ended break, possible for the PTN SG design, was modeled.

Since the FWLB is a type of loss of heat sink event, it is conservative to perform the analysis assuming that the reactor is initially operating at full power (EPU) conditions. This maximizes the difference between heat generation and heat removal between the primary and secondary cooling systems. A loss of offsite power, at both PTN units, is assumed to occur following reactor trip in order to reduce the AFW flow available to the faulted unit.

Reactor trip is assumed to occur on a SG low-low water level signal, generated when SG level reaches 0 percent of the narrow range span (NRS). It is possible that the SG water level indication could yield a false high reading, caused by a harsh environment that is produced by a FWLB occurring inside containment. Under these circumstances, the low-low SG water level signal might not be generated. In this case, the high containment pressure signal could serve as a backup, to actuate safety injection signal and reactor trip. The licensee has determined that the high containment pressure signal would be effective in preventing the loss of subcooling in the RCS, in the event that the low-low SG water level trip signal is not generated.

One AFW pump is assumed to deliver 96 gallons per minute (gpm) to each of the two intact SGs. After 10 minutes, the operator is assumed to increase this flow to 125 gpm by ending AFW flow to the faulted SG.

The FWLB analysis results indicate that the available AFW capacity would adequately remove long-term decay heat, and this would prevent saturated conditions from developing in the hot and cold legs of the RCS. This also demonstrates that the core remains covered. The SG low-low level trip signal is generated about five seconds after the FWLB occurs; the rods begin to fall into the core two seconds later; AFW flow begins 95 seconds after the trip, and becomes effective in removing decay heat (i.e., causes RCS temperatures to drop) in almost an hour.

Conclusion

The NRC staff has reviewed the licensee’s analysis of the FWLB 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 ensure that the core will remain covered during this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of PTN GDCs 30, 32, 34, and 44 following implementation of the proposed EPU.

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Partial and Complete 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. An increase in fuel temperature and accompanying fuel damage could then result if SAFDLs are exceeded during the transient. Reactor protection and safety systems are actuated to mitigate the transient.

The NRC staff's review covered:

(1) The postulated initial 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 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. GDC-10 corresponds to PTN GDC-6, “Reactor Core Design”;

(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. GDC-15 has no directly corresponding GDC in the PTN design basis;

(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. GDC-26 corresponds to PTN GDC-27, “Redundancy of Reactivity Control,” PTN GDC-28, “Reactivity Hot Shutdown Capability,” and PTN GDC-29, “Reactivity Shutdown Capability.”

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

Although the complete loss of reactor coolant flow is marginally less frequent than the partial loss of flow, and as such it may be permitted to have more severe consequences, both events are analyzed to meet the AOO analysis acceptance criteria:

(1) Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design values in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

(2) Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit.

(3) An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

Specific review criteria are contained in SRP Sections 15.3.1 and 15.3.2 and other guidance is provided in Matrix 8 of RS-001.

NRC Technical Evaluation

A loss of coolant flow may be caused by a mechanical or electrical failure in an RCP motor, a fault in the power supply to the pump motor, or a pump motor trip caused by such anomalies as overcurrent or phase imbalance. The licensee analyzed three cases: complete loss of coolant flow, with all three RCPs coasting down, RCP bus frequency decay (underfrequency) with decreasing speed in all three RCPs and partial loss of flow (PLOF), with two of the three RCPs coasting down. The acceptance criteria are based on the critical heat flux (CHF) not being exceeded and that the peak RCS and MSS pressures remain below 110 percent of their respective design pressures. Specific review criteria are found in SRP Sections 15.3.1 and 15.3.2.

The licensee used the RETRAN[114] computer code to calculate the loop and core flow during the transient, the nuclear power transient, and the primary-system pressure and temperature transients. The VIPRE[115] code was then used to calculate the heat flux and DNBR during the transient based the flow, nuclear power, and RCS temperature (enthalpy), from RETRAN.

The event was analyzed using the NRC-approved revised thermal design procedure (RTDP) assuming initial reactor power, pressurizer pressure, and RCS temperature were at their nominal values for EPU conditions.[116] Plant and initial condition uncertainties were then statistically combined and applied to the result. Assumptions were made such that the core power was maximized during the initial part of the transient when the minimum DNBR was reached.

Of the three cases run, the complete loss of flow was the most limiting case. The analysis results indicated that the minimum DNBR for both fuel types was greater than the safety analysis limit (SAL) values.

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[114] ML093421329
[115] Sung, Y. X., P. Schuren, and A. Meliksetian, Westinghouse Electric Company, “VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis,” WCAP-14565-P-A, October, 1999. ML993160153.
[116] Friedland, A.J., and S. Ray, Westinghouse Electric Corporation, “Revised Thermal Design Procedure,” WCAP-11397-P-A, April, 1989. ML080650330.

The licensee did not explicitly evaluate maximum RCS and MSS pressures because the loss of load/turbine trip (LOL/TT) event bounds the maximum RCS and MSS pressure for the loss of flow event; in a loss of flow event the turbine trips after the reactor trips. In the LOL/TT event, by comparison, the initiating event is a turbine trip allowing for the greatest primary to secondary system power mismatch that results in more severe RCS and MSS heatup and pressurization transients. Thus, the ultimate heat sink remains in place for a longer period for the loss of flow events. This reduces the peak pressure as compared to the LOL/TT events. The staff finds the licensee rationale for not analyzing peak pressures acceptable because it is based on sound phenomenology. To verify these assertions, the staff compared pressurizer pressures between the loss of load and locked rotor events and confirmed that the LOL/TT pressures are, in fact, higher.

Transient plots included showed the reactor coolant system stabilizing following the most severe portion of the event, which confirms that the event does not escalate to a more severe event without an independent fault.

Based on the following considerations:

- The licensee analyzed the event using NRC-approved codes and methods,
- The licensee analyzed three reactor coolant pump configurations to identify the most severe case, and
- The results demonstrated acceptable performance relative to the applicable acceptance criteria

The NRC staff finds the loss of reactor coolant flow analyses acceptable with respect to the proposed EPU.

Conclusion

The NRC staff has reviewed the licensee's analyses of the partial and complete loss of reactor coolant flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed EPU. See the table in Section 2.8.5, Accident and Transient Analyses, Regulatory Evaluation to see the analogous GDCs applicable to the Turkey Point GDCs. Therefore, the staff finds the proposed EPU acceptable with respect to the decrease in reactor coolant flow event.

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

Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of an RCP. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The

sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer, which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. A single rotor/shaft break analysis was preformed simulating a locked rotor for forward flow and a free-spinning shaft for reverse flow in the affected loop.

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. GDC-27 corresponds to PTN GDC-30, “Reactivity Holddown Capability”;

(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. GDC-28 corresponds to PTN GDC-32, “Maximum Reactivity Worth of Control”;

(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. GDC-31 corresponds to PTN GDC-34, “Reactor Coolant Pressure Boundary Rapid Propagation Failure Prevention.”

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

The locked rotor event is an infrequent event. Its acceptance criteria include the following:

(1) Fuel cladding damage due to increased reactor coolant temperatures must be prevented. The peak cladding temperature must remain below [[ ]]°F,[117] and cladding oxidation must be less than 16 percent.

(2) Peak main steam and reactor coolant system pressures must remain below acceptable design limits.

(3) The radiological consequences must be acceptable. For the purposes of this event, the radiological limit is fuel cladding failure associated with 15 percent rods-in-DNB.

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.

NRC Technical Evaluation

The locked rotor accident can result from an instantaneous seizure of the RCP rotor or the break of the RCP shaft.

The licensee used the RETRAN[118] and VIPRE[119] computer codes to analyze this event at EPU conditions. The licensee performed the analyses using the RETRAN computer code to calculate the loop and core flow transients, nuclear power transient, and RCS pressure and temperature transients. The licensee used the VIPRE computer code to calculate the thermal behavior of the fuel located at the core hot spot including the rods-in-DNB using the input from RETRAN.

The RTDP methodology was used. The rods-in-DNB analysis was performed at beginning of cycle (BOC) hot full power (HFP) conditions. The specific results are proprietary as discussed in Section 2.8.5.3 of the LR; however the results were within the acceptance criteria. The results also indicated significantly improved performance relative to DNB.

The licensee stated that, although the power uprate is a DNBR penalty, the overall DNBR results are improved for the EPU analysis. For the upgrade fuel, this is attributed primarily to improved DNBR performance relative to the debris resistant fuel assembly (DRFA) fuel type. In addition, for both fuel types a DNB benefit results from reduced $F_{\Delta H}$ limits (the $F_{\Delta H}$ is reduced even more for the previously-burned DRFA fuel), an increased minimum measured flow (MMF), and the use of the VIPRE transient model versus the previous use of FACTRAN/THINC for the heat flux and DNBR calculation.

The staff questioned the rods-in-DNB result in a request for additional information. On September 16, 2011,[120] in response to the RAI, the licensee provided supplemental information to support the rods-in-DNB conclusion. The licensee provided a graph showing the minimum DNBR and attendant rods-in DNB for the entire transient. The graph supported the results indicated in the licensing report. The licensee also provided both qualitative and quantitative

[117] This is a Westinghouse acceptance criterion, and it is evaluated in the Technical Evaluation.
[118] ML093421329
[119] ML993160153
[120] ML11263A003

assessments of why the percent of rods in DNB for the EPU shows significant improvement over the existing locked rotor analysis.[121] The upgrade fuel has intermediate flow mixer (IFM) grids that decrease the distance between mixing grids and increase the turbulence in the limiting DNB region. In addition to the improvements discussed above, there is an approximately 2 percent increase in minimum flow for the EPU.

The September 16, 2011, letter, referenced above, included a table that explicitly quantified the DNBR changes pre- and post-EPU. The table is proprietary and hence omitted from this SE.

The table showed that the overall net changes support the licensee's predicted increase in DNBR margin. The licensee has acceptably justified the percent of rods predicted to be in DNB at EPU conditions with the upgrade fuel. Additionally, the licensee stated that the predicted percent of rods-in-DNB that is used for dose evaluation is 15 percent and the rods in DNB calculation will be performed every cycle per the NRC approved Westinghouse reload methodology. The staff accepts this result, because it indicates that there is margin between the licensing basis radiological consequences for the event, and the results determined via safety analysis.

The peak RCS pressure was less than the acceptance criterion of 2748.5 psia. The peak cladding temperature was considerably less than the Westinghouse-identified acceptance criterion for the locked rotor event. The licensee identified an acceptance criterion limit for demonstrating a coolable core geometry of [[ ]]°F based on an October 23, 1989, Westinghouse proprietary letter to the NRC. The licensee provided various other references to support this limit in their responses to requests for additional information.

The staff does not agree with the conclusion that [[ ]]°F is an adequate limit on the cladding temperature for locked rotor events. The staff has approved a considerably lower limit, which can be found on page 27 of the SER approving the July, 2006, Optimized ZIRLO topical report.[122] The reasons for staff approval up to this limit as opposed to the limit the licensee proposed are contained in the 2006 topical report. Although the licensee provided data apparently justifying the higher limit, the staff determined that, as the predicted PCT for the PTN locked rotor event was less than both acceptance criteria, reviewing the data was beyond the scope of the EPU request. The staff finds the results acceptable on the basis that the predicted PCT is less than the lower of the two acceptance criteria discussed above. The lower limit discussed in the Optimized ZIRLO topical report is proprietary.

TCD Supplement to 2.8.5.3.2

The licensee explicitly assessed the impact of TCD on the minimum calculated DNBR values and showed that the results reported in the licensing report remain conservative with no impact. PCT calculations for the locked rotor event show an increase in PCT of 66.1°F from the value listed in the licensing report to 1890.1°F and there remains significant margin to the PCT limit of

[121] Kiley, Michael, FPL, letter to U.S. NRC, "Response to NRC Request for Additional Information Regarding Extended Power Uprate License Amendment Request No. 205," FPL Reference L-2011-426, Dockets 50-250 and 50-251, October 6, 2011. ML11280A265.
[122] Shah, H. H., Westinghouse Electric Company, "Optimized ZIRLO™," WCAP=12610-P-A & CENPD-404-P-A, Addendum 1-A, July 2006. ML062080576.

[[ ]]°F.[123] The maximum zirconium-water reaction at the core hot spot increased by 0.06% from the value listed to 0.46% and there remains significant margin to the limit of 16%. The locked rotor PCT results above are obtained by applying the maximum PAD 4.0 fuel temperatures over all burnups and the maximum peaking factors ($F\Delta H$ = 1.65 and Fq=2.4) to the analysis.

Conclusion

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

2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Rod Cluster Control Assembly Withdrawal from a Subcritical or Low-Power Startup Condition

Regulatory Evaluation

An uncontrolled rod cluster control assembly (RCCA) withdrawal from subcritical or low power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The 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 the reactor parameters used in the analysis,

(4) The analytical methods and computer codes used, and

(5) The results of the transient analyses.

The NRC's acceptance criteria are based on

(1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs. GDC-10 corresponds to PTN GDC-6, Reactor Core Design;

[123] The LR stated that the PCT limit for Locked Rotor is [[ ]]°F; however, the staff found that a value closer to [[ ]]°F was more appropriate given the NRC-reviewed in-pile data available for the ZIRLO fuel cladding product line. The licensee's TCD supplement reflects this result from the staff EPU review. See staff SER section 2.8.5.3 for additional details.

(2) GDC-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate system, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs. GDC 20 corresponds to PTN GDC-14, “Core Protection System: Core protection systems,” and PTN GDC-15, “Engineered Safety Features Protection Systems”; 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. GDC-25 corresponds to PTN GDC-31, “Reactivity Control System Malfunction.”

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

Specific review criteria are contained in SRP Section 15.4.1.

The RCCA withdrawal from subcritical or low power startup conditions is required to meet the three AOO analysis acceptance criteria:

(1) Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design values in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

(2) Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit.

(3) An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

Specific review criteria are contained in SRP Section 15.4.1 and other guidance is provided in Matrix 8 of RS-001. The staff’s application of this guidance takes into account the specific GDCs to which the PTN units were designed and licensed.

NRC Technical Evaluation

The uncontrolled RCCA withdrawal from subcritcal or low power startup condition is an AOO characterized by the insertion of positive reactivity to the reactor core due to the inadvertent withdrawal of an RCCA bank while the plant is in a subcritical or low power startup condition. As such, it is not sensitive to rated thermal power level or secondary-side conditions. The licensee re-analyzed the event to demonstrate acceptable performance at uprated power levels regardless.

The RCCA withdrawal at subcritical or low power conditions progresses with a very fast flux increase caused by the RCCA withdrawal. The reactivity feedback effect of the negative Doppler coefficient terminates the flux increase. The transient is terminated by a reactor trip. If not terminated by a reactor trip, the sequence would progress with an initial power increase followed by a power decrease from Doppler effects, followed by a slower increase in nuclear power.

As analyzed, the sequence progresses until terminated by any of source or intermediate range, or power range neutron flux low or high setting. The licensee's analysis credits the power range neutron flux-low setting, and the licensee stated that no credit is taken for the source or intermediate range trips.

The licensee also identified an intermediate rod stop, but the staff only considered the reactor protection system (RPS) features, i.e., reactor trip signals, in its evaluation. Explicit TS requirements exist for the RPS, but the regulatory treatment of the reactor control system is not necessarily as rigorous, especially for the rod stop.

The transient is analyzed in a hot zero power condition at 547 °F. When compared to shutdown conditions, the higher temperature thermal hydraulic conditions at 547 °F tend to reduce Doppler effects that compensate for the reactivity addition, and increase peak heat fluxes.

The RCCA withdrawal at low-power conditions is analyzed using the STDP, as the conditions for the transient fall outside the range of applicability of the RTDP. Conservative assumptions that are consistent with the low-power conditions were used to develop the initial conditions for this transient. These assumptions included, *inter alia*, a most-positive moderator temperature coefficient (+7 percent millirho (pcm)/°F), and a Doppler-only power defect of 1190 pcm. These reactivity parameters maximize the nuclear power transient. Assumed uncertainties on the power range high neutron flux-low setting increase it from the nominal value of 25 percent to 35 percent. Two of three reactor coolant pumps is assumed to be in operation; the licensee stated that this flow condition yields conservative DNB estimates.

The NRC staff requested additional information concerning the licensee's reactor coolant flow assumption. The staff requested that the licensee explain why the two-out-of-three pump combination was more limiting or appropriate than other conceivable configurations. The licensee responded, stating that the two-out-of-three pump combination provides a condition of reduced reactor coolant flow, while the PTN TS require that all three RCPs.[124] The staff verified that PTN TS LCOs 3.4.1.1 and 3.4.1.2 require all three reactor coolant pumps to be in operation during Modes 1-3, which comprise the operating modes under which this event would be possible. Based on this consideration, the staff agrees with the licensee assertion that the two-out-of-three pump configuration results in a lower core flow condition than would be permissible at the plant. A flow-starved condition provides for a lower DNB ratio; thus, the staff finds that the two-out-of-three RCP assumption is appropriately conservative for analysis of this event.

The licensee also stated that, in addition to the conservative degraded inlet flow due to the reactor coolant pumps assumptions, an additional flow penalty is applied to the hot bundle for additional conservatism in the hot channel DNBR analysis, consistent with NRC-approved methodology.[125, 126]

The licensee assumed a reactivity insertion rate of 75 pcm per second (pcm/sec), and confirmed that the analyzed value is based on a bounding rod worth and maximum rod speed.

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[124] ML11221A227, Page 23.
[125] ML11221A227, pp.23-24.
[126] ML993160153.

The licensee analyzed the event using the spatial neutron kinetics code TWINKLE to calculate the core average nuclear power transient, including the various core feedback effects. The FACTRAN code uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the core average heat flux and hot spot fuel temperature transients. The core average heat flux calculated by FACTRAN is finally used in the VIPRE code for DNBR calculations. These codes are NRC-approved and have been implemented in accordance with NRC-approved methods.

The licensee stated that the peak fuel centerline temperature for this transient is 2210 °F, which is significantly below the minimum temperature expected for fuel melt, 4800 °F. The minimum DNBR for this transient is 2.26, which represents significant margin to the applicable DNBR correlation limits.

The licensee provided further information to demonstrate that the location of DNBR occurred low in the core. This is a reasonable result, because core operating limits require partial insertion of the “C” bank of control rods at 0 percent power, and full insertion of the “D” bank control rods to approximately 12 percent power. The occurrence of the minimum DNBR at a lower elevation in the core, is therefore an expected result, since some rods must be fully inserted at the beginning of the transient.

No plot of DNBR versus time was provided, and the staff requested additional information to determine whether the departure from nucleate boiling was analyzed at multiple points in time. The licensee responded that the DNBR was calculated only at the time of peak core heat flux. The staff finds that this approach, although not explicitly evaluating a transient DNBR, is reasonable because the rod withdrawal event is slow-evolving, and the analytic methodology assumes high fuel and plenum heat transfer rates, so that energy is delivered to the cladding surface quickly.

The NRC staff reviewed the licensee’s analysis of the uncontrolled RCCA withdrawal from a subcritical condition and concluded that the licensee’s analysis was performed using acceptable analytical models with conservative assumptions regarding initial conditions, nuclear parameters, and mitigating RPS trip signals. The NRC staff also concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed uprate. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled RCCA withdrawal from a subcritical condition event.

Conclusion

The NRC staff has reviewed the licensee’s analyses of the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition and concludes that the licensee’s analyses have adequately accounted for the changes in core design necessary for operation of the plant at 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. See the table in Section 2.8.5, Accident and Transient Analyses, Regulatory Evaluation to see the analogous GDCs applicable to the Turkey Point

GDCs. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition.

2.8.5.4.2 Uncontrolled Rod Cluster Control Assembly Withdrawal at Power

Regulatory Evaluation

An uncontrolled RCCA withdrawal at power (RWAP) may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered

(1) The description of the causes of the AOO and the description of the event itself,

(2) The initial conditions,

(3) The values of reactor parameters used in the analysis,

(4) The analytical methods and computer codes used, and

(5) The results of the associated analyses.

The NRC's acceptance criteria are based on:

(1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs. GDC-10 corresponds to PTN GDC-6, “Reactor Core Design:;

(2) GDC-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate system, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs. GDC 20 corresponds to PTN GDC-14, “Core Protection System,” and PTN GDC-15, “Engineered Safety Features Protection Systems”; 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. GDC-25 corresponds to PTN GDC-31, “Reactivity Control System Malfunction.”

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

The RWAP is required to meet the three AOO analysis acceptance criteria:

(1) Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design values in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

(2) Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit.

(3) An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

Specific review criteria are contained in SRP Section 15.4.2 and other guidance is provided in Matrix 8 of RS-001. The staff's application of this guidance takes into account the specific GDCs to which the PTN units were designed and licensed.

NRC Technical Evaluation

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

The licensee used the RTDP to analyze this transient using a range of reactivity insertion rates at 10, 60, 80 and 100 percent NSSS power, and minimum and maximum reactivity feedback conditions. A high neutron flux reactor trip was assumed to be actuated at 115 percent of nominal full power. The licensee stated that the ΔT trips included all adverse instrumentation and setpoint errors, while delays for the trip signal actuation were assumed at their maximum values. The RCCA trip insertion characteristic assumed that the highest worth rod was stuck in its fully withdrawn position. The licensee examined a range of reactivity insertion rates from 1 pcm/sec to 80 pcm/sec. The maximum was greater than that which would be obtained from the simultaneous withdrawal of the two control rod banks having the maximum combined worth at a conservative speed. Pressurizer sprays and relief valves were assumed to be operational to limit reactor coolant pressure increase. This assumption is conservative because a low pressure will result in a more limiting DNB ratio.

The licensee used RETRAN to analyze the RWAP event. RETRAN simulated the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SGs, and MSSVs. The program calculated pertinent plant variables including temperatures, pressures, power level, and DNBR. The NRC staff accepts this calculational approach because it is in accordance with NRC-approved methodology.

The range of cases selected was consistent with SRP Section 15.4.2. For the slower reactivity insertion rates, the OTΔT trip signal was generated before the power-range high neutron flux signal. For the faster reactivity insertion rates at minimum feedback conditions, the power-range high neutron flux signal occurred first. This was also true for the full-power, maximum feedback cases. The remaining cases – maximum reactivity feedback, 80, 60, and 10 percent power – were tripped on OTΔT at all analyzed reactivity insertion rates. The lowest DNBRs were generally observed in the minimum reactivity feedback cases at the intersection of the high neutron flux and OTΔT trips. Of all analyzed cases, the lowest DNBR occurred at 10 percent power, with minimum reactivity feedback conditions. The value was 1.48, and the

reactivity insertion rate was 13 pcm/second. The EPU safety analysis limit is [[ ]], and the results are therefore acceptable.

Alternative analyses, performed using the STDP and the LOFTRAN code, with the aim of maximizing the predicted peak MSS and RCS pressures were also performed at a comprehensive combination of power levels and reactivity insertion rates to identify the cases with the limiting pressure results. For these transient sequences, the high pressurizer pressure trip was credited. The licensee determined that the limiting RCS pressure case, 2741 psia, was based on a 34 percent power case with a reactivity insertion rate of 29 pcm/second. For comparison, the licensee-identified analytic limit is 2748.5 psia. The results of this analysis establish an upper limit on the permissible reactivity insertion rate. The licensee stated that the maximum reactivity insertion rate will be confirmed on a cycle-specific basis.

The licensee has identified this reactivity insertion rate as the limiting reactivity insertion rate, which must be confirmed on a cycle-specific basis. This would mean, that for this safety analysis to be applicable to both units, the combined reactivity insertion associated with the two most reactive banks of control rods being simultaneously withdrawn at the maximum rate may not exceed this value.

The licensee presented a rather comprehensive set of analyses of the RWAP event; however, a large number of the DNB margin evaluation cases were outside the permissible reactivity insertion rate range as determined by the STDP (peak RCS pressure) analyses. The staff requested additional information because the analyses appeared to conflict with one another, especially because the DNB cases considered a very high range of reactivity insertion rates. Additional information provided by the licensee confirmed that the majority of DNB evaluations were inapplicable, but were presented for completeness.[127]

Due to the wide range of reactivity insertion rates considered, the staff also requested that the licensee indicate the maximum possible reactivity insertion rate calculated for the EPU core designs. The licensee's response indicated that there was a significant amount of margin between the maximum possible reactivity insertion rate per the EPU core design and the analyzed upper bound of reactivity insertion rates (29 pcm/sec).

Based on the licensee's responses to these requests for additional information, the staff determined that the analysis is not indicative of an unacceptably reduced amount of safety margin due to the proposed power uprate.

In conclusion, the licensee has demonstrated acceptable performance for this anticipated operational occurrence using acceptable analytic methods. The licensee also provided information to indicate that an acceptable amount of safety margin exists between the conditions analyzed and the proposed operating conditions. Based on these considerations, the NRC staff finds the licensee's analysis, and analytic results, for the RWAP event, acceptable for the proposed EPU.

[127] ML11221A227

TCD Supplement to 2.8.5.4.2

The licensee performed calculations incorporating the impact of TCD and confirmed that the maximum RCS pressure for the EPU RWAP analysis would be impacted by the increases in the maximum fuel rod temperatures, with an increase in the predicted peak RCS pressure of ~3 psi.

However, the licensee also determined that a small change in the maximum analyzed reactivity insertion rate from 29 pcm/sec to 28 pcm/sec produces results that continue to be bounded by the reported peak pressure value for the EPU RWAP analysis of 2741 psia. The licensee confirmed that existing margins in the associated core design calculations can accommodate such a reduction in the maximum reactivity insertion rate. The licensee will confirm the maximum reactivity insertion rate on a reload specific basis as part of the RSAC process.

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled RCCA withdrawal at power event and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed, uprated 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 GDCs 10, 20, and 25 following implementation of the proposed EPU. See the table in Section 2.8.5, Accident and Transient Analyses, Regulatory Evaluation to see the analogous GDCs applicable to the Turkey Point GDCs. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled RCCA withdrawal at power.

2.8.5.4.3 Rod Cluster Control Assembly Misoperation

Regulatory Evaluation

The NRC staff's review covered the types of control rod misoperations that are assumed to occur, including those caused by a system malfunction or operator error. The review covered:

(1) Descriptions of rod position, flux, pressure, and temperature indication systems, and those actions initiated by these systems (e.g., turbine runback, rod withdrawal prohibit, rod block) which can mitigate the effects or prevent the occurrence of various misoperations;

(2) The sequence of events;

(3) The analytical model used for analyses;

(4) Important inputs to the calculations; and

(5) The results of the analyses.

The NRC's acceptance criteria are based on:

(1) GDC-10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs. GDC-10 corresponds to PTN GDC-6, "Reactor Core Design";

(2) GDC-20, insofar as it requires that the reactor protection system be designed to initiate automatically the operation of appropriate system, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs. GDC 20 corresponds to PTN GDC-14, "Core Protection System," and PTN GDC-15, "Engineered Safety Features Protection Systems"; 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. GDC-25 corresponds to PTN GDC-31, "Reactivity Control System Malfunction."

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

The RCCA misoperation is required to meet the three AOO analysis acceptance criteria:

(1) Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design values in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

(2) Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit.

(3) An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

Specific review criteria are contained in SRP Section 15.4.3 and other guidance is provided in Matrix 8 of RS-001. The staff's application of this guidance takes into account the specific GDCs to which the PTN units were designed and licensed.

<u>NRC Technical Evaluation</u>

The RCCA misoperation events are AOOs that include these incidents:

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

These are transients that are driven by core reactivity and nuclear flux responses to changes in rod positions and are not sensitive to secondary-side conditions. The topical report, WCAP-11394-P-A, "Methodology for the Analysis of the Dropped Rod Event," provides a generic

procedure for use in analyzing this class of events.[128] The generic dropped RCCA statepoints are evaluated in each cycle as part of the reload safety evaluation process in order to demonstrate that the applicable DNB design basis is satisfied. Use of this NRC-accepted, dropped rod methodology has shown that the DNBR SAL is not exceeded and the acceptance criteria continue to be met.

The staff agreed with the approach for the RCCA misoperation events in the context of the Turkey Point Units 3 and 4 uprate. Therefore, the NRC staff agreed the licensing basis acceptance criteria continue to be met and found the RCCA misalignment evaluation acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses of control rod misoperation events and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The 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 GDCs 10, 20, and 25 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to control rod misoperation events.

2.8.5.4.4 Startup of an Inactive Reactor Coolant 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.

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[128] Haessler, R. L., et al., Westinghouse Electric Corporation, "Methodology for the Analysis of the Dropped Rod Event," WCAP-11394-P-A, January 1990. ML100040440.

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. GDC-10 corresponds to PTN GDC-6, "Reactor Core Design";

(2) GDC-20, insofar as it requires that the protection system be designed to automatically initiate the operation of appropriate systems to ensure that SAFDLs are not exceeded as a result of operational occurrences. GDC-20 corresponds to PTN GDC-14, "Core Protection System";

(3) GDC-15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during AOOs. GDC-15 has no directly corresponding GDC in the PTN design basis;

(4) GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core. GDC 28 corresponds to PTN GDC-32, Maximum Reactivity Worth of Control; and

(5) GDC-26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. GDC-26 corresponds to PTN GDC-27, Redundancy of Reactivity Control, PTN GDC-28, Reactivity Hot Shutdown Capability, and PTN GDC-29, Reactivity Shutdown Capability.

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

Specific review criteria are contained in SRP Section 15.4.4 and other guidance is provided in Matrix 8 of RS-001. The staff's application of this guidance takes into account the specific GDCs to which the PTN units were designed and licensed.

<u>NRC Technical Evaluation</u>

If the plant is operating with one reactor coolant pump out of service, there would be reverse flow through the inactive loop due to the pressure difference across the reactor vessel. The cold leg temperature in an inactive loop is identical to the cold leg temperature of the active loops (the reactor core inlet temperature). If the reactor is operated at power, and assuming the secondary side of the steam generator in the inactive loop is not isolated, there would be a temperature drop across the steam generator in the inactive loop and, with the reverse flow, the hot leg temperature of the inactive loop would be lower than the reactor core inlet temperature.

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

Conclusion

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

2.8.5.4.5 Inadvertent Reactor Coolant System Boron Dilution Event

Regulatory Evaluation

Unborated water can be added to the RCS, via the chemical and volume control system (CVCS). This may happen inadvertently because of operator error or CVCS malfunction, and cause an unwanted increase in reactivity and a decrease in shutdown margin. The operator should stop this unplanned dilution before the shutdown margin is eliminated.

The NRC staff's review covered:

(1) Conditions at the time of the unplanned dilution,

(2) Causes,

(3) Initiating events,

(4) The sequence of events,

(5) The analytical model used for analyses,

(6) The values of parameters used in the analytical model, and

(7) Results of the analyses.

The NRC's acceptance criteria are based on:

(1) GDC-10, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including AOOs. GDC-10 corresponds to PTN GDC-6, "Reactor Core Design";

(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. GDC-15 has no directly corresponding GDC in the PTN design basis; 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. GDC-26

corresponds to PTN GDC-27, Redundancy of Reactivity Control, PTN GDC-28, "Reactivity Hot Shutdown Capability," and PTN GDC-29, "Reactivity Shutdown Capability."

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

SRP Section 15.4.6 stipulates that boron dilution events be considered for all modes of operation. Typically, the way licensees show acceptable results for this transient is to demonstrate the operators have sufficient time to terminate the boron dilution before a complete loss of SDM. If SDM is not lost then the reactor does not return to criticality and boron dilution is bounded by other analysis. This is the means by which the PTN licensee has chosen to demonstrate acceptable results. The SRP acceptance criteria are that the operators have at least 15 minutes from notification of the onset of a boron dilution event until a complete loss of SDM for Modes 1, 2, 3, 4, and 5, and at least 30 minutes in Mode 6.

Specific review criteria are contained in SRP Section 15.4.6 and other guidance provided in Matrix 8 of RS-001.

NRC Technical Evaluation

Reactivity can be added to the core by feeding primary water into the RCS via the reactor makeup portion of the CVCS. Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. The CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value that, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner.

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

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

Boron Dilution Parameters

Operating Condition	**Boron Concentration (ppm)**		**Dilution Flow (gpm)**	**Dilution Volume (ft^3)**
	Initial	**Critical**		
Mode 1 Auto Rod Control	1900	1550	252	7619.5
Mode 1 Manual Rod Control	1900	1550	252	7619.5
Mode 2 Startup	2000	1800	252	7619.5
Mode 3	1800	1700	150	6987.0

Mode 4 RCP	1690	1600	150	6987.0
Mode 4 RHR	1778	1600	150	3579.7
Mode 5 Filled	1770	1600	150	3579.7
Mode 5 Drained	1779	1600	150	2951.0
Mode 5 Partially Drained	1779	1600	150	3146.5
Mode 6	2300	1600	252	2951.0

MODE 1 (At-Power)

The licensee stated that, based on the available RCS volume of 7619.5 ft^3 and the maximum dilution flow of 252 gpm based on simultaneous operation of three charging pumps, 32.5 minutes are available to secure the dilution flow in automatic rod control. 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 power range high neutron flux trip or the OTΔT trip setpoint, resulting in a reactor trip. There are 30 minutes available for operator action with the rod control system in manual to secure the dilution flow.

MODE 2 (Startup)

The licensee considered the maximum dilution flow of 252 gpm with a reactor coolant system volume of 7619.5 ft^3. Boron dilution would be indicated by core monitoring hardware providing input to high source level and all reactor trip alarms. The licensee stated that 17.7 minutes are available between operator indication of dilution and loss of SDM.

MODES 3 and 4 (Hot Standby and Hot Shutdown)

The licensee stated that boron dilution analysis for MODES 3 and 4 is not part of the PTN licensing basis. However, after discussion and RAIs from the staff, PTN provided analysis during MODES 3 and 4 and as a result has submitted a license amendment increasing the shutdown margin per Figure 3.1-1 of the reference.[129] The increase was necessary to assure adequate operator response time is available to identify and terminate an inadvertent dilution event prior to loss of all shutdown margin.

MODE 5 (Cold Shutdown)

The licensee stated that boron dilution analysis for MODE 5 is not part of the PTN 4 licensing basis. However, after discussion and RAIs from the staff, PTN provided analysis during MODE 5 and as a result have submitted a license amendment (Reference 1) increasing the

[129] Kiley, Michael, FPL, letter to U.S. NRC, "Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request No. 205," FPL Reference L-2011-438, Dockets 50-250 and 50-251, October 15, 2011. ML11292A032.

shutdown margin from 1 to 1.77. The increase was necessary to assure adequate operator response time is available to identify and terminate an inadvertent dilution event prior to loss of all shutdown margin.

MODE 6 (Refueling)

The MODE 6 analysis assumes a reduced volume RCS inventory (2951.0 ft^3) and 252 gpm dilution associated with three charging pumps. The licensee calculated a value in excess of thirty minutes from event initiation to loss of shutdown margin.

The following table shows the PTN EPU results for the boron dilution event.

CVCS Malfunction Boron Dilution Event Results

Condition	**Current**	**EPU**	**Limit**
Mode 1 Auto Rod Control	31.5 Minutes	32.5 Minutes	15 Minutes
Mode 1 Manual Rod Control	30.3 Minutes	30.0 Minutes	15 Minutes
Mode 2	17.0 Minutes	17.7 Minutes	15 Minutes
Mode 3	NA	15.01 minutes	15 Minutes
Mode 4 RCP	NA	17.15 Minutes	15 Minutes
Mode 4 RHR		16.94 Minutes	15 Minutes
Mode 5 Filled	NA	17.35 Minutes	15 Minutes
Mode 5 Drained		15.02 Minutes	15 Minutes
Mode 5 Partially Drained		16.02 Minutes	15 Minutes
Mode 6	30.01 Minutes	31.2 Minutes	30 Minutes

The EPU analysis results shown in this are more favorable than the results for the current analysis. A significant contributor to the difference in results is the larger and less limiting dilution volume for the Modes 1 and 2 EPU calculations resulting from accounting for the 10 percent steam generator tube plugging level specified for the EPU. The current analysis considered 20 percent steam generator tube plugging resulting in a smaller and more limiting dilution volume. The boron concentrations used in the current analysis with a smaller (more limiting) delta between the initial and critical concentrations are a significant contributor to the results shown for Mode 6.

For Modes 1, 2, and 6 the licensee used the a dilution flow rate of 252 gpm. For Modes 3, 4, and 5 the licensee used a maximum dilution flow rate of 150 gpm in the supplemental analysis. The licensee stated:

> The maximum dilution flow rate of 150 gpm bounds the makeup flow that is required to maintain pressurizer water level when letdown flow is maximized. Maximum letdown flow is 120 gpm, but there are additional reactor coolant losses that correspond to allowable reactor coolant system leakage (11 gpm) and reactor coolant pump seal leakoff (15 gpm) that have been considered. The maximum dilution flow of 252 gpm that

was applied in the boron dilution analyses for operating Modes 1, 2, and 6 is a very conservative dilution flow that corresponds to three charging pumps in operation.

Through audit, the licensee provided additional information for the basis of the 150 gpm boron dilution flowrate in Modes 3, 4, and 5. Postulated boron dilution events are assumed to initiate from normal plant conditions. The licensee stated that three charging pumps are never placed in service for normal operation and that three would only be used to make up for off-normal excessive RCS leakage greater than the capacity of two charging pumps. For Modes 3, 4, and 5 the licensee used different initial conditions than the very conservative Modes 1, 2, and 6 initial conditions. They are:

- Two Charging Pumps in operation with a flow of 146 gpm
- Two 60 gpm letdown flow orifices in services for a total of 120 gpm
- RCP seal water return of 15 gpm
- RCS leakage of 11 gpm

The analysis then assumes a conservative charging flow of 150 gpm balanced with 150 total flow from letdown, RCP seal leak-off and RCS leakage. The licensee stated that the original analysis used the full flow from all three charging pumps even though that condition does not happen in normal plant operation. After reviewing the information provided, the staff agreed that the analysis for flowrate during a boron dilution event in Modes 3, 4, and 5 is acceptable.

As can be seen from the above table, the licensee has sufficient margin for its Mode 1 and 2 analyses. For its PTN Mode 3, 4 and 5 analyses, the licensee must show the operator has at least 15 minutes from initiation of the boron dilution event until all SDM is lost. Because the licensee has demonstrated there are 15.01 minutes in Mode 3, a minimum of 16.94 minutes in Mode 4, and a minimum of 15.02 minutes in Mode 5, for operator action, the results are found to be acceptable. For PTN Mode 6 analysis, the licensee must show the operator has at least 30 minutes from imitation of the boron dilution even until SDM is lost. As the licensee has demonstrated there are 31.2 minutes available for operator action, this result is also 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 adequately address plant operation at the proposed, uprated condition. The staff finds the proposed uprate acceptable with respect to the CVCS malfunction event.

2.8.5.4.6 Spectrum of RCCA Ejection Accidents

Regulatory Evaluation

Control rod ejection accidents cause a rapid positive reactivity insertion together with an adverse core power distribution, which could lead to localized fuel rod damage. The NRC staff evaluates the consequences of a control rod ejection accident to determine the potential damage caused to the RCPB and to determine whether the fuel damage resulting from such an accident could impair cooling water flow. The 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 which affect the peak reactor pressure or the probability of fuel rod failure, and the results of the transient analyses.

The NRC's acceptance criteria are based on GDC-28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to impair significantly the capability to cool the core. GDC-28 corresponds to PTN GDC-32, "Maximum Reactivity Worth of Control."

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

Specific review criteria are contained in SRP Section 15.4.8 and other guidance provided in Matrix 8 of RS-001.

NRC Technical Evaluation

RCCA ejection accidents cause a rapid positive reactivity insertion together with an adverse power distribution that could lead to localized fuel damage. Since the key acceptance criterion is maximum fuel stored energy, initial plant conditions are selected to maximize fuel stored energy. This event is considered at 0 percent and 100 percent power, and at BOC and EOC.

The licensee applied acceptance criteria to its analysis based on experimental testing and on conclusions drawn in WCAP-7588.[130] Analytical limits on stored energy are 200 cal/g for both irradiated and unirradiated fuel, and fuel melt must remain less than 10 percent of the pellet volume at the hot spot. Acceptance for pressure surges is based on not exceeding faulted-condition stress limits, and the licensee provided a generic disposition for this criterion.

The NRC staff observes that these acceptance criteria are more rigorous than those contained in RG 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors." The calculation of the RCCA ejection accidents is performed using a two-stage process. An average core calculation is performed using the TWINKLE spatial neutron kinetics code, followed by a hot spot analysis using FACTRAN.

The control rod ejection accident analyses for PTN were performed assuming the EPU power level, at BOC and EOC. The full-power cases indicated that 3.37 percent and 0.4 percent of the fuel would melt (BOC and EOC). The corresponding maximum fuel stored energy was 172.9 and 156.3 cal/g. For the zero power cases, there was no fuel melt, and the maximum fuel stored energy was 86.8 and 138.0 cal/g (BOC and EOC).

As a result of a fuel failure during a test at the CABRI reactor in France in 1993, and one in 1994 at the NSRR test reactor in Japan, the NRC recognized that high burnup fuel cladding might fail during a reactivity insertion accident (RIA), such as an RCCA ejection, at lower enthalpies than the limits currently specified in RG 1.77. However, generic analyses performed by all of the reactor vendors have indicated that the fuel enthalpy during RIAs will be much

[130] Risher, D.H., Westinghouse Electric Corporation, "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors Using Special Kinetics Methods," WCAP-7588, January 1975.

lower than the RG 1.77 limits, based on their 3D neutronics calculations. For high burnup fuel which has been burned so long that it no longer contains significant reactivity, the fuel enthalpies calculated using the 3D models are expected to be much less than 100 cal/g.

The staff has concluded that although the RG 1.77 limits may not be conservative for cladding failure, the analyses performed by the vendors, which have been confirmed by NRC-sponsored calculations, provide reasonable assurance that the effects of postulated RIAs in operating plants with fuel burnups up to 60 gigawatt days per metric ton uranium will neither: (1) result in damage to the reactor coolant pressure boundary, not (2) sufficiently disturb the core, its support structures, or other reactor pressure vessel internals to impair significantly the capability to cool the core as specified in the current regulatory requirements.

A generic calculation of the pressure surge for an ejected rod worth of one dollar at BOL, HFP, indicated that the peak pressure would not exceed faulted condition stress limits for the RPV. The PTN EPU rod ejection events continue to be bounded by this analysis.

Since fuel and clad enthalpy limits are not exceeded, there is no danger of sudden fuel dispersal into the coolant, and since the peak pressure does not exceed the faulted condition stress limits, there is no danger of additional damage to the RCS. The analyses demonstrate that the fission product release as a result of fuel rods entering DNB is limited to less than 10 percent of the fuel rods in the core.

The staff confirmed the validity of the results through an audit. Westinghouse provided the calculation notebook as well as a table that the staff used to verify the results. The table showed that for HFP BOL conditions, the safety analysis was based on an ejected rod worth that was 9.2 times the maximum cycle-specific value for the reference EPU core design. For the EOC case, the safety analysis value for the ejected rod worth exceeded the reference core maximum value by 4.2 times. Therefore, the BOC results may be expected to be roughly a factor of two “more conservative” than the EOC results. The analyzed peaking factors at both beginning and end of cycle conditions also exceeded cycle-specific design values by a factor of approximately two. The staff concluded, from its audit, that the results of the RCCA ejection accident were reasonable because there was substantial margin between the analytic inputs and the cycle-specific design values.

<u>TCD Supplement to 2.8.5.4.6</u>

The licensee updated its control rod ejection accident analyses by modifying its FACTRAN inputs to incorporate the effects of TCD. The greatest effect was that associated with fuel melting in the hot full power cases.

The control rod ejection accident analyses for PTN were performed assuming the EPU power level, at BOC and EOC. The full-power cases indicated that 8.23 percent and 8.44 percent of the fuel would melt (BOC and EOC). The corresponding maximum fuel stored energy was 321 and 306.3 BTU/lbm. For the zero power cases, there was still no fuel melt, and the maximum fuel stored energy was 157.6 and 249.3 BTU/lbm (BOC and EOC).

Conclusion

The NRC staff has reviewed the licensee's analyses of the rod ejection accident and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The staff further concludes that the licensee has demonstrated that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could (1) result in damage to the RCPB greater than limited local yielding, or (2) cause sufficient damage that would significantly impair the capability to cool the core. Based on this, the staff concludes that the plant will continue to meet the requirements of PTN GDC 32 and 33 following implementation of the proposed EPU. Therefore, the staff finds the proposed EPU acceptable with respect to the rod ejection accident.

2.8.5.5 Increase in 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 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. GDC-10 corresponds to PTN GDC-6, "Reactor Core Design";

(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. GDC-15 has no directly corresponding GDC in the PTN design basis; 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. GDC-26 corresponds to PTN GDC-27, “Redundancy of Reactivity Control,” PTN GDC-28, “Reactivity Hot Shutdown Capability,” and PTN GDC-29, “Reactivity Shutdown Capability.”

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

Increases in reactor coolant inventory are required to meet the three AOO analysis acceptance criteria:

(1) Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design values in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

(2) Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit.

(3) An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

Specific review criteria are contained in SRP Section 15.5 and other guidance provided in Matrix 8 of RS-001.

NRC Technical Evaluation

Inadvertent ECCS Actuation

An inadvertent actuation of the ECCS at power event, an AOO, could be caused by operator error or a false electrical actuation signal. At PTN, the ECCS consists of three accumulators, two low head injection pumps, and four high head injection pumps. During power operations, the high head safety injection pumps are incapable of delivering flow to the RCS because the pumps’ shut-off head is 3250 ft, or approximately 1400 psi, which is less than the normal RCS operating pressure of 2,250 psia. Therefore, the licensee stated, inadvertent ECCS actuation is not a possible initiator of an inadvertent increase in reactor coolant inventory.

Note that the RCS depressurization caused by the inadvertent opening of a pressurizer safety or relief valve can cause the RCS to depressurize below the shutoff head of safety injection pumps. Therefore, the NRC staff finds that the licensee is correct in that ECCS actuation caused by operator error or spurious initiation signal is not a possible initiator of an inadvertent increase in reactor coolant inventory. However, the plant response to the inadvertent pressurizer safety or relief valve opening will result in an ECCS actuation that increases the reactor coolant inventory. This event is evaluated further in Section 2.8.5.6.1 of this safety evaluation.

CVCS Malfunction

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 spurious actuating signal. At PTN, the charging system is normally in operation. While it can deliver a maximum flow of 252 gpm conservatively, the normal charging flow is maintained at 69 gpm (45 gpm charging line flow and 24 gpm RCP seal injection). Should charging flow become excessive relative to the RCS inventory make-up requirement, alarms would alert the operator to high pressurizer level, high pressurizer pressure, and low volume control tank level. If operator action is not taken to secure the excessive charging flow, a reactor trip on high pressurizer level would occur. If the pressurizer fills and causes water to be relieved through the PORVs or safety valves, then these valves could stick open and create an SBLOCA, which is a more severe event. This would violate the acceptance criterion that prohibits the escalation of an AOO into a more serious event. Satisfaction of this acceptance criterion is demonstrated by showing that sufficient time exists for the operator to recognize the situation and end the charging flow before the pressurizer can fill.

The effect of adding water inventory to the RCS, with no change in boron concentration, would be an increase in pressurizer water level. Under the proposed EPU conditions, the nominal pressurizer water level will be 60 percent with an uncertainty of ±5.8 percent at T_{avg} of 583 °F. At EPU conditions, the highest pressurizer water level could, therefore, be 65.8 percent corresponding to a minimum pressurizer steam volume of 470 ft^3. At the maximum charging flow rate and neglecting lifting of the charging line relief valves, the licensee calculated that the operator would have a minimum time of 14 minutes before the pressurizer is filled. The normal configuration for PTN is to have one charging pump running, and the charging pumps must be started manually.

The licensee calculation demonstrates that the CVCS malfunction could be secured by the operator in 14 minutes, and the calculation is based on an initial pressurizer steam volume that is small, in combination with a charging flow higher than the total charging capacity at PTN. The combination of a small steam volume and high charging flow ensures that the pressurizer fill time is conservatively calculated. The result is consistent with SRP Section 15.5.2, which states 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. Because the licensee-calculated pressurizer fill time exceeds that discussed in the SRP, the staff finds the result acceptable.

This transient is typically benign with respect to the other two acceptance criteria, DNB and RCS overpressure protection, because the event evolves slowly and does not involve a reactivity transient, as the boron dilution is analyzed and evaluated as a different AOO. The overpressurization event is bounded by the transients discussed in Sections 2.8.4.2 and 2.8.5.2 of this safety evaluation. The boron dilution event associated with a CVCS malfunction is discussed in Section 2.8.5.4.5 of this Safety Evaluation.

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent operation of ECCS and CVCS 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 calculations. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of PTN GDCs 6 and 29 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent operation of ECCS and CVCS event.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of a Pressurizer 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 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. GDC-10 corresponds to PTN GDC-6, "Reactor Core Design";

(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. GDC-15 has no directly corresponding GDC in the PTN design basis; 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. GDC-26 corresponds to PTN GDC-27, "Redundancy of Reactivity Control," PTN GDC-28, "Reactivity Hot Shutdown Capability," and PTN GDC-29, "Reactivity Shutdown Capability."

See Section 2.8.5 for further information regarding the GDCs in the PTN design basis.

Inadvertent openings of primary system relief valves are required to meet the three AOO analysis acceptance criteria:

(1) Pressure in the reactor coolant and main steam systems should be maintained below 110 percent of the design values in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

(2) Fuel cladding integrity shall be maintained by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains above the 95/95 DNBR limit.

(3) An AOO should not generate a postulated accident without other faults occurring independently or result in a consequential loss of function of the RCS or reactor containment barriers.

Specific review criteria are contained in SRP Section 15.6 and other guidance provided in Matrix 8 of RS-001.

NRC Technical Evaluation

The licensee stated that the consequences of this event are bounded by the PTN small break loss of coolant accident. The staff does not accept this disposition.

The inadvertent opening of a pressurizer PORV is an equipment malfunction and not a pipe break. It is an AOO. It causes a depressurization of the reactor coolant system and presents a challenge to the DNBR safety limiit as the RCS pressure drops. If action is not taken to secure the open valve, by either closing the PORV or its block valve, the event could escalate to a small break LOCA as the licensee stated, which is contrary to the nonescalation criterion set forth for AOOs.

The licensee did not analyze this event because it is not in the PTN current licensing basis.[131] In response to the NRC staff RAI concerning the analysis and acceptance criteria for this event, the licensee also stated that PTN would respond in a similar fashion to other plants for which this event is analyzed. This would include a gradual RCS depressurization accompanied by a slight decrease in DNBR. The DNBR transient would be mild.

This event, were it to occur, would be terminated either by the DNB-protective over-temperature ΔT trip or the low pressurizer pressure trip. The OTΔT trip is the primary DNB-protective trip; its setpoint changes as reactor conditions change. The setpoint is adjusted as core temperature difference, reactor coolant system pressure, and nuclear power deviate from their nominal values.

In PTN Final Safety Analysis Report Chapter 3, “Reactor,” Section 3.1, “Design Basis,” it is stated, “the reactor control and protection system is designed to actuate a reactor trip for an anticipated combination of plant conditions, when necessary, to ensure a minimum departure from nucleate boiling (DNB) ratio greater than or equal to the DNBR limit of the applicable DNB correlation.”

[131] ML11221A227.

PTN FSAR Section 7.2 states, "the purpose of this [[ ]] trip is to protect the core against DNB. This trips the reactor on coincidence of two of the three signals, with one set of temperature measurements per loop. The set point for this reactor trip is continuously calculated for each loop by solving the equation provided in Section 2.2 of the Technical Specifications."

Current PTN TS 2.2 provides the OTΔT setpoint equation as follows.[132]

$$\Delta T \cdot \tilde{\tau}_1 \leq \Delta T_0 \left[K_1 - K_2 \cdot \tilde{\tau}_2 \left(T \cdot \tilde{\tau}_3 - T'\right) + K_3 \left(P - P'\right) - f_1 \Delta I\right]$$

Where:

ΔT	=	Measured core ΔT by RTD information
τ	=	Lead-lag compensators
ΔT_0	=	Indicated ΔT at rated thermal power
K_1, K_2	=	Constants
T	=	Average temperature
T'	=	Nominal average temperature at rated thermal power
K_3	=	Pressure-compensation coefficient
P	=	Pressurizer pressure
P'	=	Nominal pressurizer pressure at rated thermal power
fΔI	=	Correction for axial flux difference

The quantity K_3(P-P') is a pressure compensation term. It is the portion of the setpoint equation that is responsible for adjusting the trip setpoint for given increases or decreases in reactor pressure. The licensee proposes to change the value of K_3 from 0.001 as currently contained in the TS to 0.00116. This means that the licensee has proposed to change the amount by which the trip setpoint will change for any given change in reactor pressure.

The licensee did not provide the appropriate safety analyses that are required to validate the newly proposed value of the pressure compensation coefficient against the plant-specific conditions associated with operating at the proposed, uprated power level.

In the case of some prior power uprates, the NRC staff had considered the licensees' assertions that the DNB transient associated with an RCS depressurization would be mild, because similar plants had safety analyses demonstrating the validity of this assertion. The staff was thus able to refer to those plants' safety analyses and confirm that, indeed, the associated DNB transient was mild and that the pressure compensation coefficient was adequately chosen.

Although there are some uprated plants roughly analogous to PTN, some fundamental design differences exist relative to the postulated RCS depressurization:

[132] PTN TS 2.2 at ML052790649. Note that this equation has been simplified from the form contained in the TS. The expressions for the specific lead-lag compensators (the tau terms in the equation) are simplified.

- PTN contains significantly smaller pressurizer power operated relief and safety valves.
- Some engineered safeguards features, notably the high head safety injection system, are shared between the PTN units, resulting in a significantly different mass injection that would follow the postulated PTN PORV opening transient.

Based on the proposed plant changes described above, and on the design difference between PTN and its uprated sister units, the NRC staff was unable to accept the licensee's assertions without safety analyses that validated the newly chosen OTΔT trip setpoint equation pressure compensation coefficient, and requested that the licensee provide a plant-specific validation analysis of the RCS depressurization event. The analyses were required in order to demonstrate to the staff that the setpoint equation had been so chosen as to correct an abnormal occurrence before the DNB safety limit is exceeded, consistent with the reactor design basis requirement contained in the PTN FSAR as well as with the requirement promulgated in 10 CFR 50.36(c)(ii)(a).

The licensee provided a safety analysis by letter dated September 30, 2011, in attempt to abate the staff's concern.[133] The initiating event for the analysis was a spurious opening of a pressurizer safety valve. In terms of an anticipated operational occurrence resulting in an RCS depressurization, this is an acceptable analysis because the safety valves are roughly 1.6 times larger than the power-operated relief valves, and thus depressurize the RCS more quickly, resulting in a more severe departure from nucleate boiling transient.

The event was analyzed using the RETRAN code in accordance with standard, NRC-approved, Westinghouse safety analysis methodology.[134]

The results provided by the licensee indicated that the reactor would trip on OTΔT with a minimum DNBR slightly above 1.5, resulting in minimum DNBR margin of [[ ]] percent. This means that the DNBR remained above its safety limit. Based on the licensee's use of a conservative initiating event assumption and NRC-approved methodology, and on the fact that the DNBR results were acceptable, the staff found the licensee's analysis acceptable.

Figure 2.3.1-5 of the September 30, 2011, letter, was a plot of pressurizer level as a function of time for the postulated opening of the pressurizer safety valve. The plot indicated, toward the tail end, a brisk insurge into the pressurizer. During followup conversations, the licensee indicated that this was attributable to hot leg saturation following the postulated event.

While the information provided by the licensee indicated that the results were acceptable with respect to the first two acceptance criteria for a Condition II event, i.e., acceptable DNBR and peak pressure, the plots left the third acceptance criterion – that the event would not escalate to a more severe event – unaddressed.

Some time after the reactor trip, and after the minimum DNBR has been reached, the continuing RCS depressurization will cause a low pressurizer pressure SI signal to be generated. The

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[133] Kiley, Michael, FPL, letter to U.S. NRC, "Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request No. 205," FPL Reference L-2011-400, Dockets 50-250 and 50-251, September 30, 2011. ML11276A080.
[134] ML993160153.

delivery of SI water into the RCS can, if it exceeds the PORV relief rate, cause the pressurizer level to increase up to and including the water solid condition.

The PTN SI system uses centrifugal pumps. The rate of SI flow into the RCS will increase as the RCS depressurizes. When the pressurizer become water solid, water begins to flow through the open PORV. If the PORV is not qualified for water relief, then it is likely the PORV will not close upon demand. In this way, the inadvertent opening of a PORV, an AOO, becomes a small break LOCA at the top of the pressurizer, a Condition III event. This scenario violates the third acceptance criterion.

The NRC staff requested that the licensee address the inadvertent opening of the PORV with respect to the third criterion. The licensee provided an analysis, performed largely in accordance with NRC-approved, Westinghouse analytic methodology using the RETRAN computer code; however, this analysis was performed assuming that the PORV opened instead of the safety valve.[135] Assuming the opening of the PORV is acceptable, because the safety valve is differently qualified, and reseats mechanically. An additional independent fault would be required to cause the safety valve to fail to close. The SI system flow was assumed to be at its maximum.

The analysis indicated that the pressurizer would fill within about 240 seconds. The licensee also stated that there are multiple alarms to indicate the opening of a PORV, including a direct alarm, a tailpipe temperature alarm, and a pressure-related alarm. The licensee also stated that a prompt operator action is required to close the PORV, and if a response is not obtained, i.e., the PORV does not close, the operator is to close the block valve. Prompt operator actions are committed to memory and require SRO concurrence. The specific action requires turning a switch to close either the PORV or its block valve.

Because the required actions are prompt, and because they are simple, the NRC staff agrees that the analyzed 240 seconds provides enough time to secure the inadvertently open PORV without filling the pressurizer.

In summary, the NRC staff disagreed with the licensee's original disposition of this event. In response, the licensee produced safety analyses, using NRC-approved codes and methods, that demonstrated that this event would not challenge fuel cladding or RCS pressure boundary integrity, or that this event would escalate into a more serious event. Based on these considerations, the NRC staff finds the requested power uprate acceptable with respect to the inadvertent opening of a pressurizer safety or relief valve.

During an audit at the PTN site, the NRC staff observed a scenario in the PTN simulator. The staff observed operators responding to the inadvertent opening of a power operated relief valve. The specific scenario was a failure of a pressure transmitter, which caused the PORV to open even though there was no reactor system perturbation. An annunciator alerted the operators that the PORV had opened. Operators then announced the condition, and promptly took action to close the open PORV. No reactor protection or safeguards systems actuated. The operator

[135] Kiley, Michael, FPL, letter to U.S. NRC, "Response to NRC Reactor Systems Branch Request for Additional Information Regarding Extended Power Uprate License Amendment Request No. 205," FPL Reference L-2011-444, Dockets 50-250 and 50-251, October 14, 2011. ML11292A033.

response to close the open PORV took less than ten seconds, indicating substantial margin to the analyzed 4-5 minute pressurizer fill time. Based on its audit observations, the NRC staff concluded that there was acceptable margin between the operator response time and the required operator intervention time that was determined via the safety analysis.

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. 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 GDCs 10, 15, and 26 following implementation of the proposed EPU. See the table in Section 2.8.5, Accident and Transient Analyses, Regulatory Evaluation to see the analogous GDCs applicable to the Turkey Point GDCs. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent opening of a pressurizer pressure relief valve event.

2.8.5.6.2 Steam Generator Tube Rupture

Regulatory Evaluation

A steam generator tube rupture (SGTR) event causes a direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and main steam safety or atmospheric relief valves. Reactor protection and ESFs are actuated to mitigate the accident and restrict the offsite dose to within the guidelines of 10 CFR Part 50.67.

The NRC staff's review covered:

(1) Postulated initial core and plant conditions;

(2) Method of thermal and hydraulic analysis;

(3) The sequence of events (assuming offsite power either available or unavailable);

(4) Assumed reactions of reactor system components;

(5) Functional and operational characteristics of the RPS;

(6) Operator actions consistent with the plant's emergency operating procedures (EOPs); and

(7) The results of the accident analysis.

The NRC staff's review of the SGTR is focused on the thermal and hydraulic analysis for the SGTR in order to: (1) determine whether 10 CFR 50.67 is satisfied with respect to radiological consequences, which are discussed in Section 2.7 of this safety evaluation; and (2) confirm that

the faulted SG does not experience an overfill. Preventing SG overfill is necessary in order to prevent radioactive liquid releases to the environment and to prevent the failure of main steam lines.

The most specific review criteria for this event are set forth in SRP Chapter 15.6.3; however, SRP Chapter 15.6.3 has not been revised since 1981. Guidance contained for reviewing Accident Source Terms, as published in SRP 15.0.1 and RG 1.183 is more relevant to the Turkey Point licensing basis, since the plant has implemented an alternate source term. Consistent with this regulatory guidance, the NRC staff reviewed the licensee's analyses to determine that there was reasonable assurance that the licensing basis analysis providing inputs to the radiological consequences analyses was appropriately bounding and conservative.

NRC Technical Evaluation

A SGTR accident, and ANS Condition IV event, will transfer radioactive reactor coolant to the shell side of the SG as a result of the ruptured tube, and ultimately to the atmosphere. Therefore, the SGTR analyses for the proposed power uprate were performed to show that the resulting onsite and offsite doses will stay within the allowable guidelines and there was margin available to provide reasonable assurance that SG overfilling is unlikely. This review considers the thermal hydraulic modeling, and not the radiological consequences.

Licensing Basis (Steam-Only Mass Release) Analyses

The SGTR analyses consider the complete severance of one steam generator tube. Other assumptions are a NSSS power level of 2644 MWt, nominal RCS pressure, RCS T_{ave} of 570°F to 583°F, 0 percent to 10 percent steam generator tube plugging, a low pressurizer pressure SI actuation setpoint of 1745 psia, and maximum SI flow from the high head pumps.

The licensee modeled four cases, with minimum and maximum steam generator tube plugging, and high and low RCS average temperature. The licensee identified conditions that would optimize mass release in consideration of pressure differences between the RCS and the MSS, while considering that lower secondary pressures and temperatures would reduce the steam generator enthalpy and thus have a deleterious – somewhat nonconservative – effect on the flashing prediction. The licensee determined that the highest possible pre-trip flashing fraction based on the range of operating conditions covered by this analysis is for a case with a hot leg temperature of 616.8°F and initial secondary pressure of 701 psia. The post-trip RCS pressure is assumed to be 1476 psia and the SG pressure 959 psia. Hot leg temperature is assumed not to be reduced for 30 minutes, and RCS saturation is assumed, despite that operating procedures require operators to prevent a loss of subcooling. The saturated RCS assumption is only employed because it is conservative, not because it is expected to exist.

The licensing basis analytic results, including the integrated tube rupture break flow, flashed break flow, and integrated atmospheric steam releases, are provided. The licensee stated that the maximum primary to secondary break flow assumption is based on the case with 10 percent tube plugging and 570°F RCS T_{ave}. The maximum steam release was obtained from the calculation for the initial 30 minutes is based on the results of the case modeling 0 percent tube plugging, and 583°F RCS T_{ave}. The licensee included margin on the calculated break flow and steam releases in order to bound future modifications that may affect the tube rupture results so

that a recalculation of radiological consequences would not be necessary. The results are listed in Table 2.8.5.6.2-1 of the licensing report; there are no acceptance criteria for the results because they are inputs to the radiological consequence analysis.

The licensing basis analysis does not explicitly model operator actions, although it is assumed that break flow into the ruptured steam generator secondary side is terminated within 30 minutes.

To confirm that the licensing basis analysis is acceptably conservative, the licensee performed two supplemental analyses using more realistic assumptions to demonstrate that (1) the licensing basis flashed break flow and atmospheric steam releases are conservative, and (2) the assumption of a steam-only atmospheric release is appropriate because the ruptured steam generator has margin to overfill (MTO).

Table 2.8.5.6.2-5 compares the key licensing basis analysis results to limiting results from a supplemental thermal hydraulic analysis.

The NRC staff accepts the licensee's analysis and results because they are based on conservative assumptions, and because two supplemental thermal hydraulic analyses, performed using more sophisticated methods, demonstrate that the licensing basis calculation is quite conservative. The staff's evaluation of the two confirmatory analyses follows.

Extended Release Supplemental Thermal Hydraulic Analysis

The licensing basis analysis assumes that the break flow into the ruptured steam generator is terminated within 30 minutes. The licensee noted that the present licensing basis does not necessarily require such action to be taken, and the reactor coolant may continue to blow down into the ruptured steam generator beyond 30 minutes. Therefore, the licensee performed a supplemental thermal-hydraulic analysis with assumptions intended to maximize the mass release to demonstrate that, even though the break flow may not be terminated within 30 minutes, the licensing basis analysis predicts conservative radiological consequences and is thus valid.

This analysis is performed using the NRC-accepted LOFTTR-2 code,[136] which is a variant of the LOFTRAN code specifically designed to model tube rupture events. The LOFTTR-2 analysis explicitly models operator actions consistent with the progression through plant procedures that would occur during the analyzed event.

Although WCAP-10698-P-A, and other analyses using the LOFTTR-2 code tend to use assumptions intended to deliver a pessimistic result with respect to the parameter of interest – either margin to overfill, or in this case, mass release – the licensee identified a precedent where an NRC licensee had used the LOFTTR-2 code and certain nominal inputs to deliver a

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[136] Lewis, R. N., et al., Westinghouse Electric Corporation, "Steam Generator Tube Rupture Analysis Methodology to Determine the Margin to Steam Generator Overfill," WCAP-10698-P-A, August 1987, ML071430455. This WCAP is the analytic methodology employed using the LOFTTR-2 code, and presents the methodology and conservative inputs for margin-to-overfill evaluations; a different set of limiting initial conditions would be used in the limiting steam release calculation. The official record copies of WCAP-10698-P-A, along with its non-proprietary companion report, WCAP-10750, are contained in the legacy file system.

more nominal result. The licensee chose to follow this precedent. Although this approach is suitable for validating the licensing basis technique, the staff does not find that this approach provides an acceptably conservative prediction of mass release, despite its apparently successful use in a prior application.[137]

Compared to the licensing basis analysis discussed above, the extended release results predicted a 57 percent higher total tube rupture break flow and a 10 percent increase in intact steam generator steam releases, but a 49 percent reduction in flashed break flow. The atmospheric release from the ruptured steam generator was also 22 percent less in the extended release model when compared to the licensing basis analysis. These comparisons enumerate the conservatism of the licensing basis analytic technique.

The licensee omitted the consideration of a limiting single failure, assumed nominal plant conditions without consideration of uncertainty, and reduced conservatism on the initial secondary mass. In the case of this extended release analysis, the results of this analysis were acceptable to the staff because there remained such a large difference between the predicted flashing fractions and atmospheric steam releases that the licensing basis results were clearly conservative, despite any additional penalties that could be included to account for parametric uncertainties and permissible variations in assumed initial conditions.

The key reason for the large differences in results between the licensing basis analysis and the extended release analysis is that the extended release analysis uses a flashing fraction that is based on the thermal-hydraulic conditions calculated by the code, and they are time-dependent. The licensing basis conservatively assumes one flashing fraction pre-trip, and another post-trip. The licensing basis analysis is performed to maximize the flashing fraction.

Based on the considerations discussed above, the NRC staff finds that, while the thermal hydraulic extended release analysis was not performed using conventionally accepted best practices for deterministic safety analyses, it remains acceptable because it still provides a credible demonstration that the licensing basis analysis is quite conservative.

Margin To Overfill[138]

The licensing basis radiological consequence analysis for the postulated tube rupture event is based on a scenario where the radiological release is steam-only. The radiological consequence analysis assumes that the secondary side of the steam generator does not overfill with liquid as a result of the event. This assumption is validated by performing a separate thermal-hydraulic analysis to demonstrate that, under a different set of limiting initial conditions, the ruptured steam generator does not overfill. This is the margin to overfill (MTO) analysis.

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[137] Stang, J. F., USNRC, letter to Robert Powers, Indiana Michigan Power Company, “Donald C. Cook Nuclear Plant, Units 1 and 2 – Issuance of Amendments (TAC No. MB0739 and MB0740),” Dockets 50-315 and 50-316, October 24, 2001. ML012690136.

[138] Kiley, Michael, FPL, letter to U.S. NRC, “Response to NRC Request for Additional Information Regarding Extended Power Uprate License Amendment Request Number 205 and Safety Analyses Issues – Round 1,” FPL Reference L-2011-028, Dockets 50-250 and 50-251, March 16, 2011. ML110770019. The analysis described in this letter superseded Section 2.8.5.6.2, ‘Evaluation of Margin to Overfill,’ of the Licensing Report. The analysis described in the licensing report was not suitably conservative, and the replacing analysis more closely aligned to the method described in WCAP-10698-P-A.

The acceptable analytic approach described in WCAP-10698 includes the following conservative assumptions: (1) a concurrent loss of offsite power, (2) initial conditions that are bounding of expected plant operation, and (3) a limiting single failure.[139] The limiting single failure assumed in the WCAP-10698 reference plant analysis is the failure of a steam generator (SG) power operated relief valve (PORV) on an intact steam generator to open. The safety function of the PORV was accomplished by another SG PORV opening in another, unaffected steam generator.

The licensee performed analyses for margin to overfill that aligned closely with the method described in WCAP-10698, with a noted exception based on the Turkey Point design basis. Turkey Point is not designed to mitigate a postulated steam generator tube rupture with a single failure; hence, the licensee does not include a limiting single failure in its analyses. The staff finds this exception acceptable since RS-001 states that the staff will review plants against the current design basis.[140]

The licensee based its MTO analyses on updated operator response times that were recorded in the plant simulator by observing various crews' responses. The licensee stated that the analyzed response times bounded those that were observed. This is an acceptable approach because the use of bounding response times is conservative, and the response times that are significant to the safety analyses become time-critical operator actions, which are then validated in the simulator through operator training and examination.

The results of the analysis indicated that 300 ft^3 of available margin to overfill would remain in the ruptured generator, thus validating the assumption that the mass releases calculated from a limiting steam-only release are suitably conservative. The results also indicated that the break flow from this case would be terminated by equalizing the tube- and shell-side pressures in the ruptured steam generator in approximately 50 minutes. Note that this is a shorter blowdown period than the extended release analysis assumes as indicated in LR Table 2.8.5.6.2-4.

The licensee provided a table comparing WCAP-10698 modeling assumptions to those used in the MTO analysis for Turkey Point EPU. There were few differences. The licensee used minimum auxiliary feedwater temperature and decay heat levels instead of the maximum values used in the generic report; such use at Turkey Point was shown to be conservative by sensitivity analysis. Also, the licensee did not model the automatic OTΔT turbine runback system as in WCAP-10698, because this system does not exist at Turkey Point. The staff accepts these departures because they conservatively reflect Turkey Point-specific plant design aspects.

The licensee indicated that the following equipment credited for mitigating the tube rupture event is nonsafety-related: radiation monitors, instrument air compressors, and steam dump to condenser valves. The staff observed that the intact steam generator pressures remain at the main steam safety valve setpoints until a cooldown using the intact steam generator is initiated; it is therefore not clear what purposes the steam dump to condenser valves serve. In any case,

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[139] Although this safety evaluation report discusses the limiting single failure identified in WCAP-10698, note that the WCAP also specifies that the limiting single failure depends on the main steam system design, which is highly plant-specific.
[140] ML033640024

the licensee stated that a loss of offsite power was assumed in the analysis, meaning that the condenser would not be available as a place to dump steam. The steam will be relieved through the steam generator atmospheric dump valves.

There are three sets of quality-related main steam radiation monitors to help identify a ruptured generator; however, the licensee indicated that operators are directed to perform steam line surveys and monitor steam generator level indications to identify the affected steam generator.

Power-operated relief valves on the pressurizer, and atmospheric dump valves on the steam generators, are safety-related with nitrogen backups.

Information provided by the licensee indicated that a very small subset of mitigating equipment for the margin to overfill analysis was nonsafety-related. In the case where nonsafety-related equipment had been identified, it was either determined not to be used or was backed up by multiple, diverse equipment, such that there was reasonable assurance that the function being performed by nonsafety-related equipment would be available by multiple other means.

Based on the following considerations: (1) the licensee performed an analysis of margin to overfill largely consistent with WCAP-10698 with noted exceptions for the PTN design basis, (2) the licensee validated its operator action timing inputs in the Turkey Point simulator, (3) the analysis demonstrated 300 ft^3 of margin to overfill, and (4) the licensee relied on minimal, nonsafety-related mitigating equipment, which had multiple backups, the NRC staff finds the licensee's margin to overfill analysis acceptable.

Conclusion

In conclusion, the licensee used a conservative calculation, crediting no operator actions, to calculate the mass released under a postulated steam generator tube rupture event. The licensee also provided two supporting analyses to demonstrate the conservatism of the calculation and validate the assumption that the release would be steam-only. Based on the NRC staff's review, the NRC staff finds that the calculation provides reasonably conservative inputs to the licensee's radiological consequences evaluation.

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

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

Regulatory Evaluation

LOCAs are postulated accidents that would result in the loss of reactor coolant from piping breaks in the RCPB at a rate in excess of the capability of the normal reactor coolant makeup system to replenish it. Loss of significant quantities of reactor coolant would prevent heat

removal from the reactor core, unless the water is replenished. The reactor protection and ECCS systems are provided to mitigate these accidents.

The NRC staff's review covered:

(1) The licensee's determination of break locations and break sizes,

(2) Postulated initial conditions,

(3) The sequence of events,

(4) The analytical model used for analyses,

(5) Calculations of peak cladding temperature, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling,

(6) Functional and operational characteristics of the reactor protection system and ECCS, and

(7) Operator actions.

The NRC's acceptance criteria are based on:

(1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance, applicable as below:

    (i) 10 CFR 50.46(a)(1)(i) contains the requirements for realistic ECCS evaluation models, or

    (ii) 10 CFR 50.46(a)(1)(ii) states that ECCS evaluation models may conform to the required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA as established in Appendix K to 10 CFR Part 50,

(2) 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,

(3) GDC-27, insofar as it requires that reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained, and

(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 at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented.

The aforementioned GDCs, published in 10 CFR 50, Appendix A, were not yet available at the time the PTN units were licensed to operate. The PTN units were designed and licensed according to earlier GDCs, proposed by the Atomic Energy Commission, that are discussed in PTN FSAR Section 1.3. In this case, the GDC equivalents for GDCs 4, 27, and 35 are proposed GDCs 40, 30, and 44.

GDC-35 is directly applicable to PTN insofar as 10 CFR 50.46(d) states that the requirements of 10 CFR 50.46 are in implementation of the general requirements with respect to ECCS cooling performance design set forth in 10 CFR Part 50, including in particular GDC-35 of Appendix A.

Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance is provided in Matrix 8 of RS-001.

NRC Technical Evaluation

The staff evaluation of the PTN Units 3 and 4 emergency core cooling system (ECCS) performance consisted of reviewing the results of the large and small break LOCA analyses performed at 2652 Mwt (including uncertainty) and a peak linear heat generation rate of 16.56 kW/ft. The staff also reviewed the results of the post-LOCA long term cooling analyses to show that the plant emergency operating procedures can properly deal with and control the build-up of boric acid accumulation in the RCS following both large and small break LOCAs. The EOPS specify the latest time at which hot leg injection must be initiated to prevent further build up following a LOCA.

The NRC staff evaluated the large and small break LOCA analyses and post-LOCA long term cooling analyses for the PTN Units 3 and 4. The NRC staff's evaluation also included an audit of Westinghouse calculations pertaining to boric acid precipitation analyses and timing for the switch to hot leg injection. The NRC staff performed independent hand calculations to investigate the potential for core uncover following interruption of ECC injection during large and small break LOCAs.

2.8.5.6.3.1 Large Break Loss-of-Coolant Accident

In concert with the proposed EPU, the licensee will be making a slight change to its current licensing basis methodology for ECCS evaluations under postulated large break LOCA conditions.

In the current licensing basis, the licensee uses the code qualification document (CQD) methodology. Westinghouse obtained generic NRC approval of its original topical report describing the best-estimate (BE) LBLOCA methodology in 1996 for 3 and 4-loop PWRs. This method is known as the CQD methodology.[141] NRC approval of the methodology is documented in the NRC safety evaluation report appended to the topical report.

[141] Bajorek, S. M., et. al., Westinghouse Electric Company, "Code Qualification Document for Best Estimate LOCA Analysis," WCAP-12845-P-A, 1998. Available as an NRC-internal reference under Package No. ML080630386.

Westinghouse completed a program to revise the statistical approach used to develop the peak cladding temperature (PCT) and oxidation results at the 95th percentile. This method is based on the CQD methodology and follows the steps in the code scaling applicability and uncertainty (CSAU) methodology [NUREG/CR- 5249]. However, the uncertainty analysis (Element 3 in CSAU) is replaced by a technique based on order statistics. The Automated Statistical Treatment of Uncertainty Method (ASTRUM) methodology replaces the response surface technique with a statistical sampling method in which the uncertainty parameters are simultaneously sampled for each case. The approved ASTRUM evaluation model is documented in WCAP-16009-P-A.[142]

The CQD-based, pre-EPU LOCA analysis was performed for PTN at the current licensed thermal power level of 2300 megawatts-thermal (MWt). FSAR Section 14.3.2.1 indicates that the current licensing basis LBLOCA analysis predicted a PCT of 2067 °F.

The proposed ASTRUM analysis was performed for the Turkey Point units operating at an assumed extended power uprate power level of 2652 MWt, and showed a limiting PCT of 2064 °F. The licensee stated that FPL Energy and its vendor, Westinghouse Electric Company LLC, continue to have ongoing processes which ensure that LOCA analysis input values conservatively bound current operating values.

The full results are tabulated below.

Parameter	**ASTRUM Results**	**10 CFR 50.46 Limits**
Peak Cladding Temperature	2064 °F	2200 °F
Local Metal Oxidation	4.25%	17%
Core-Wide Oxidation	0.43%	1%

Statistically, the staff determined that the greatest number of cases, 24, occurred in the 1600 °F-1650°F temperature range. The upper bound PCT was 2064 °F, a value that exceeded all other cases by at least 70 °F. The lowest predicted PCT from the population of runs was approximately 1000 °F.

The NRC staff reviewed the information submitted by the licensee and concluded that the ASTRUM method is NRC-approved to analyze LBLOCAs at three-loop Westinghouse plants such as PTN, and that the licensee's analysis demonstrates acceptable performance relative to the 10 CFR 50.46 acceptance criteria at uprated conditions. In consideration of these items, the NRC staff finds the licensee's request to implement ASTRUM acceptable. The NRC staff's finding is based not only on the considerations discussed above, but also on its supplemental evaluation of the selected topics described below.

[142] Westinghouse Electric Company, "Realistic Large Break LOCA Evaluation Methodology Using Automated Statistical Treatment of Uncertainty Method," WCAP-16009, March 11, 2005, ADAMS Accession Number ML050910157.

Downcomer Nodalization

The licensee used a nine node downcomer model in its WCOBRA/TRAC analyses. This model adds detail to improve the prediction of downcomer boiling that occurs later in the LOCA event. In the limiting LOCA results, the PCT occurs early – on the order of 50 seconds – and downcomer boiling begins at approximately 125 seconds, as indicated by depressions in the lower plenum collapsed liquid level in Licensing Report Figure 2.8.5.6.3.2-11.

The licensee provided plots of two-phase conditions at various elevations in the downcomer in response to a staff RAI.[143] High initial voiding lower in the downcomer early in the transient indicates that the model is predicting a period of emergency core cooling sweepout, where the safety injection flow enters the downcomer, travels around it, and out the break. The plots also showed a tendency for the void fraction to begin stabilizing at approximately 250 seconds, and decreasing at approximately 300 seconds. This trend was observable at all levels of the downcomer.

During an audit, the licensee provided plots of core collapsed levels to show that stable and increasing core liquid levels were maintained in all channels out to 2000 seconds. The downcomer void fraction plots, in combination with the plots shown during the audit, indicate that the model is predicting downcomer boiling, and that the core does not undergo an unexpected heatup later in the transient. The staff finds these results acceptable.

Input Parameter Assessment

Members of the international regulatory community have expressed recent interest in the correlation of sampled input parameters to permissible operating conditions at a nuclear power plant.[144] In light of this interest and of the high-PCT upper tolerance limit results generated by the PTN EPU ECCS evaluation, the staff reviewed some of the statistical aspects of the ASTRUM demonstration analysis furnished by the licensee. The staff requested that the licensee provide input data to assess how well the code inputs reflected permissible and actual plant operation. The licensee provided data files tabulating the analytic input data for each case, and histograms of observed safety injection temperatures and accumulator pressures.

Consistent with ASTRUM, TS-limited analytic inputs use a sampling range that bounds the limiting conditions for operation established for the plant. The sampling method employed in ASTRUM is based on the idea that more numerical dispersion occurs in the various WCOBRA-TRAC analyses than typically occurs at the plant, thus ensuring that the upper-bound results are generally bounding of plant operation.

The staff reviewed the data provided by the licensee. The staff compiled several scatter plots of various sampled input parameters as functions of peak cladding temperature. The plots showed well-scattered inputs, and provided a reasonable confirmation that this execution of

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[143] ML11221A227

[144] Mendizábal, R., and F. Pelayo, "Best-Estimate Plus Uncertainty Methods and Plant Technical Specifications," *Proceedings of the ASME 2010 3rd Join US-European Fluids Engineering Summer Meeting and 8th International Conference on Nanochannels, Microchannels, and Minichannels, 1-5 August 2010,* Montreal, Canada.

ASTRUM generated random inputs that were consistent with the generic ASTRUM input parameter sampling strategy. As the data used to generate these plots were proprietary, they are withheld from this safety evaluation.

The staff evaluated the assumed safety injection (refueling water storage tank) temperature. The licensee provided the sampled safety injection temperature input parameters, along with a histogram showing historical surveillance temperatures. The staff compared the histogram to the sampled distribution.

In accordance with the ASTRUM method, the safety injection temperature is sampled from a distribution that promotes numerical dispersion to its tail. The ASTRUM-generated WCOBRA/TRAC input data illustrated that the sampling followed the sampled distribution reasonably well. The surveillance data showed that the actual temperatures trend toward the higher end of the sampled range. The staff's comparison of analytic sampling to surveillance trending data confirmed that the ASTRUM-generated inputs bounded the surveillance data reasonably well.

The staff also inspected the assumed safety injection temperature, along with accumulator cover gas pressure and accumulator liquid volume, as a function of predicted peak cladding temperature. The staff determined that the cases were well distributed, with a good spread of assumed safety injection characteristics at both ends of the PCT distribution. Most notably, the highest PCT case had a relatively degraded ECCS condition (i.e., higher than nominal SI temperatures, lower than nominal accumulator cover pressure). Although the third highest case was assigned an SI temperature that was among the lowest in the population, the remaining SI temperatures assumed for the top five highest PCT cases are well distributed and include some more degraded cases.

The staff's investigation of the assumed safety injection parameters reveals that it is suitably distributed and has enough scatter to introduce variability in the PCT results, and provides an acceptable input to the calculations. The statistical dispersion in the input parameters, and the corresponding range of PCT predictions (from 950 °F to 2050 °F) provide a general confirmation that the ASTRUM method predicts an acceptable upper tolerance limit of the predicted peak cladding temperature.

Decay Heat Assessment

In reviews of recent requests to implement best-estimate large break LOCA ECCS evaluation models, the staff has been requesting additional information concerning the analytic treatment of decay heat. The treatment of decay heat for the PTN EPU ASTRUM analyses is described generically in Chapter 8 of WCAP-16009. The staff requested additional information to confirm how the decay heat model is implemented in a plant-specific analysis, and more specifically, how the plant-specific analyses treat the decay heat uncertainty.

During an audit, the licensee provided additional information concerning the treatment of decay heat. The decay heat is treated in a fashion that is similar to other uncertainty attributes in the ASTRUM methodology. In two of the five highest PCT cases from the ASTRUM analysis, the decay heat value included an uncertainty that was greater than nominal. In the PTN application,

however, since the PCT occurs early in the transient, the fuel stored energy contributes more significantly to the cladding heatup.

Based on two considerations: (1) the ASTRUM methodology is NRC-approved for modeling the LBLOCA at a three-loop Westinghouse plant; and (2) the PTN-specific results show acceptable ECCS performance relative to the 10 CFR 50.46 acceptance criteria, the NRC staff finds that the licensee's ASTRUM analyses support the requested extended power uprate for PTN. The staff's further evaluation of key phenomena, including the downcomer boiling problem, the input parameter statistics, and the comparison of the analytic inputs to operational data, provide further evidence that ASTRUM calculated an acceptable upper tolerance limit prediction of the 10 CFR 50.46(b) parameters.

<u>TCD Supplement to 2.8.5.6.3.1</u>

ASTRUM IMPLEMENTATION REVISIONS

Background

The ASTRUM evaluation model addresses uncertainties in the model and the plant operating state. These parameters are not entirely independent contributors to the peak cladding temperature uncertainty, and therefore their uncertainties cannot be summed algebraically. The ASTRUM therefore assesses total uncertainty by varying each of the uncertainty categories simultaneously. The process is accomplished by executing 124 thermal-hydraulic code runs, and the model characteristics and operating state inputs for each run are randomly sampled from a specified operating range.

Examples of ASTRUM-sampled uncertainty attributes include:

- Marviken critical flow data
- Downcomer condensation
- Fuel conductivity
- Refill and reflood heat transfer coefficients
- Peaking factors
- ECCS initial conditions

ASTRUM/PAD4.0 Correction

The licensee used the corrected version of PAD to generate inputs to the ASTRUM execution. In the typical ASTRUM analysis, the WCOBRA/TRAC initialization generates the fuel conditions using a MATPRO analytic procedure. The initial conditions are also calculated using PAD4.0, and then the WCOBRA/TRAC fuel temperature is corrected to the PAD fuel temperature by adjusting plenum heat transfer properties. With the improved PAD correction, the STAV model in WCOBRA/TRAC is used for the initialization, instead. The STAV model more closely simulates the fuel performance predicted by PAD4.0TCD than the MATPRO model.

Compensating Model Changes

To offset the TCD error, the licensee updated some sampled inputs by imposing operating limit restrictions, or changing the analysis so that it was more consistent with plant requirements, i.e., by eliminating conservatism in the analytic input. The specific changes were as follows:

- [[ ]]:
    - o Accumulator minimum water volume was adjusted from 862 to 875 ft^3.
    - o Axial peaking factor FdH was reduced.
    - o FQ was reduced.
- [[ ]]:
    - o Minimum full-power normal operating vessel average temperature was increased from 570°F to 577°F.
    - o Maximum steam generator tube plugging was adjusted from 10% to 5%.
    - o High head safety injection delay time with offsite power available was reduced from 23 to 17 seconds.

The sampled uncertainty attributes were adjusted by changing the function used to generate the input value from the random number. The accumulator volume function is considered as an example.

Because the accumulator volume is sampled from a uniform distribution, the parametric distribution can be described by a simple linear equation:

$$V_{acc} = \left(\frac{V_{max}}{V_{min}} - 1\right) x + V_{min}$$

The WCOBRA/TRAC inputs were adjusted by substituting the new value of V_{min} into the equation above. Similar adjustments to the WCOBRA/TRAC inputs were made for the peaking factors.

The fixed parameters were adjusted by changing their input values. [[

]].

Recognizing that the prior ASTRUM run demonstrated 95/95 confidence in a PCT upper tolerance limit of 2063 °F, the licensee examined the TCD impact by re-analyzing all of the 124 thermal-hydraulic analyses.

The licensee considered whether to perform the analysis using the same statistical seed values as from the analysis performed before the TCD error was identified, or to generate new statistical seed. Ultimately, the licensee deferred to existing Westinghouse practices with respect regenerating the analytic seed. The licensee used the existing seed values.

[[

]].

Results

The updated analysis determined that the limiting case exhibited a peak cladding temperature of 2093 °F. The licensee also explicitly analyzed IFBA fuel and determined that the IFBA fuel would increase the PCT by 59 °F. The PCT penalty for mixed core effects is 12 °F. The total PCT is, therefore, 2164 °F. The maximum local oxidation result is 10.46%, and the core wide oxidation is less than 0.40%. These values remain within the regulatory acceptance criteria of 2200 °F, 17%, and 1%, respectively. Because the updated values meet the regulatory acceptance criteria, they are acceptable.

NRC Staff Conclusion

The licensee's analyses demonstrate that the compensating changes to plant operation will offset the TCD effect sufficiently to allow operation at the proposed, uprated power level in compliance with 10 CFR 50.46 requirements. The corrected analysis shows that there is a high level of probability that the 10 CFR 50.46(b) acceptance criteria will not be exceeded during the most severe postulated loss of coolant accidents. On this basis, the staff finds the licensee's corrected large break LOCA analysis acceptable.

2.8.5.6.3.2 Small Break Loss of Coolant Accident

The small break LOCA (SBLOCA) includes all postulated pipe ruptures with a total cross sectional area less than 1.0 square foot. The SBLOCAs analyzed in this section are for those breaks beyond the makeup capability of a single charging pump, and hence, require actuation of the ECCS. The licensee's analyses were performed to demonstrate compliance with the 10 CFR 50.46 requirements for the conditions associated with Turkey Point, operating at its uprated power level.

The licensee has analyzed the SBLOCA using a methodology consistent with its current licensing basis. The licensee will continue to use the NRC-approved NOTRUMP code, documented in WCAP-10054-P-A, "Westinghouse Small Break LOCA Evaluation Model Using the NOTRUMP Code," and NRC-approved changes to the methodology to evaluate the SBLOCA. The methodology includes calculation of the system thermal hydraulic response

using the NOTRUMP code, and the effects of fuel rod heat up using the SBLOCTA code, which in turn demonstrates the acceptability of peak clad temperature, cladding oxidation, and hydrogen generation results. These methods contain conservative assumptions in order to develop analytic results in accordance with the requirements set forth in Appendix K to 10 CFR Part 50.

For the PTN SBLOCA analysis, FPL analyzed a spectrum of cold leg breaks that included 1.5, 2, 3, 4, and 6-inch breaks. The licensee also considered an 8.75-inch accumulator line break, and found that the 4-inch cold leg break produced the limiting peak clad temperature. The results, shown below, demonstrate significant margin to both the predicted peak cladding temperatures predicted for the large break LOCA analyses and the 10 CFR 50.46 limit of 2200 °F.

Parameter	**Result**	**10 CFR 50.46 Limit**
Limiting Break Size	4.0-in	N/A
Peak Clad Temperature	1231°F	2200°F
Maximum Local Oxidation	0.07%	17%
Maximum Core-Wide Oxidation	.01%	1.0%

Paragraph (a)(1)(i) of 10 CFR 50.46 states in part that "ECCS cooling performance… must be calculated for a number of postulated loss-of-coolant accidents of different sizes, locations, and other properties sufficient to provide assurance that the most severe postulated loss-of-coolant accidents are calculated." While integer break size evaluations are too coarse to identify the most limiting small break, the very low temperature of the limiting break demonstrates considerable margin relative to the 2200 °F criterion limit, and to the relatively more severe limiting large break LOCAs.

The licensee references, in its LR, LTR-NRC-06-44, "Response to NRC Request for Additional Information on the Analyzed Break Spectrum for the Small Break Loss of Coolant Accident NOTRUMP Evaluation Model, Revision 1," Gresham, J.A., July 2006. The referenced letter presents some sensitivity studies for various Westinghouse 3- and 4-loop plants and asserts that for lower PCT plants, the break spectrum phenomena are well characterized by the analyzed integer break spectrum as was done for PTN. In the PTN-specific case, for example, the licensee justified the coarse break spectrum as follows (emphasis added for clarity):[145]

> For the Turkey Point Units 3 and 4 EPU **3-inch break**, the RCS depressurizes relatively slowly, reaching a pressure slightly below the accumulator gas cover pressure late in the transient; the accumulator flow remains relatively low such that the core **recovers primarily on high-head safety injection.** For the **6-inch break**, the initial rate of RCS mass loss and depressurization is relatively high and the RCS quickly depressurizes (sic) which **results in the accumulators injecting a large amount of inventory early in the transient** recovering the core prior to any significant fuel rod heat-up. The **4-inch break** experiences rates of mass loss and depressurization greater than those of the 3-inch break and less than those of the 6-inch break. The accumulators … **are not sufficient to**

[145] ML11221A227

> **recover the core prior to experiencing fuel-rod heat-up** …. The competing effects of vessel depletion and [[ ]] delivery with increasing break size… lead to the limiting cladding heat-up. **For Turkey Point Units 3 and 4, this break size occurs between 3 and 6 inches, and is <u>well-characterized</u> by the 4-inch break**.

Although the passage above does not assert that the 4-inch break is the limiting size in the small break spectrum, it does assert that the limiting break would exhibit similar behavior.

The Gresham letter referenced above concludes that, in the case that the small break spectrum results in a low PCT, a course break spectrum provides an acceptable analysis. The threshold is selected to remain below a 1700 °F limit based on the chemical kinetics of the Baker-Just oxidation model where oxidation becomes significant above 1700 °F. The letter also adopts, as a criterion, that the large break PCT significantly exceeds the small break PCT. This criterion ensures that the passage in 10 CFR 50.46(a)(1)(i), quoted above, remains satisfied, because there is adequate assurance that the large break PCT would remain bounding of any small break PCT generated using a finer break spectrum. In other words, the staff can be adequately assured that the most severe postulated LOCA has been calculated, because the limiting large break PCT is so much higher than the potentially nonlimiting – albeit by a marginal amount – small break PCT.

The PTN large break LOCA analyses resulted in a PCT of 2064 °F, compared to the small break LOCA result, which was 1231 °F. With a difference of 833 °F between the two values, the staff agrees that the difference is significant. It is the staff's experience that a coarsely analyzed small break spectrum may under-predict the limiting small break PCT by about 500 °F or, in most cases where this issue has been identified and pursued, less. Therefore, the staff finds that the criteria above – PCT less than 1700 °F and large break PCT significantly higher than the small break PCT – apply to PTN and the use of the coarser break spectrum is justified.

As such, the staff does not require additional small break analyses to characterize the small break spectrum more accurately. The staff finds the small break LOCA analysis acceptable, demonstrating a large margin to the 2200 °F criterion limit in 10 CFR 50.46(b). The large break analyses provide assurance that the sufficient break sizes and locations criterion of 10 CFR 50.46(a)(1)(i) are satisfied.

Shared ECCS Components

During review, the staff compared the EPU small break LOCA results to the current licensing basis (CLB) results. The current licensing basis results, according to the most recent UFSAR revision available to the staff, the SBLOCA limiting results are for the 3-inch break with a PCT of 1688°F. The staff determined that the results were so different because the current licensing basis analyses assume unitized safety injection systems, whereas the proposed EPU analyses credit the actual PTN safety injection configuration. At PTN, a safety injection signal will cause both Unit 3 and Unit 4 high head safety injection systems to actuate and align to the distressed unit. Therefore, the licensee credited one high head safety injection from each unit to inject on a small break LOCA demand. This added high head safety injection flow is largely responsible for the improvement in PTN SBLOCA results.

The staff reviewed the PTN licensing basis and identified no criteria that would preclude the crediting of this somewhat unique ECCS configuration. Therefore, the staff did not object to the licensee's crediting two of four shared high head safety injection systems to mitigate the consequences of a small break LOCA at one PTN unit.

Loop Seal Clearing

During some small break LOCAs, liquid water may remain in the low points of the reactor coolant loops, leaving the loops completely filled. This phenomenon prevents steam from travelling through all of the loops in an unobstructed fashion, which increases the loop hydrostatic resistance. The increased hydrostatic resistance can depress the two-phase mixture level in the core, and cause a cladding heat-up. If the model does not predict the key phenomena correctly, it may overpredict the steam flow through the liquid-filled loop seals, reducing the hydrostatic resistance and causing an artificial increase in the two-phase liquid level in the core. This would cause an inadequate model to under-predict the PCT.

The NRC staff requested that the licensee address the availability of additional experimental data regarding the behavior of loop seal clearing, and discuss whether the NOTRUMP model was consistent with this data. The licensee responded to state that the original NOTRUMP model had been validated against code-to-code comparisons, as well as SEMI-SCALE and Westinghouse air-water test data.[146] Since that time, ROSA, UPTF, and VVER data confirming the results of the previous data set became available. The licensee stated that the NOTRUMP model remained consistent with the newer data.

The licensee also provided additional information concerning the NOTRUMP method and its modeling with regard to the key phenomena relevant to reactor coolant loop seal clearing. The licensee stated that, while its two-phase flow models for flow through the reactor coolant loops are somewhat simple, an artificial restriction that limits loop seal clearing only to the loop with the break ensures that the code does not provide a non-conservative representation of the phenomena key to loop seal clearing. This threshold, a proprietary break size, is consistent with the available experimental data. The limiting break in the small break spectrum analyzed for Turkey Point assumed that only the broken loop seal cleared. The staff is therefore assured that loop seal clearing has been treated conservatively in the limiting small break accident analyzed.

In conclusion, the NRC staff finds the licensee's small break loss of coolant accident analyses acceptable in that the NOTRUMP model has demonstrated that the small break accidents remain within the acceptance criteria promulgated at 10 CFR 50.46(b).

2.8.5.6.3.3 Post-LOCA Long-Term Core Cooling

Large and Small Break Behavior

The licensee has provided an assessment of small break post-LOCA 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

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[146] MLL11221A227

of boric acid precipitation for small break LOCAs has also, therefore, been demonstrated. Of particular importance is the EOP action to initiate a cooldown for small breaks no later than one hour post-LOCA. This operator action will assure small breaks, which may not allow sufficient hot and cold leg injection to establish a flushing flow, will refill with injection and reestablish single phase natural circulation that will remove the boric acid built up during the early portion of the small break LOCA. As discussed below, the staff finds the procedures and analysis of intermediate and small break LOCA boric acid control acceptable.

The NRC staff audit calculations confirm the precipitation timing for the limiting large break LOCA of approximately 6.5 hrs compared to 6.7 hrs from the licensee evaluation. The precipitation limit is 29.27 wt%.

The major assumptions in the licensee's boric acid precipitation analysis are:

Core power	= 2652 MWt (including uncertainty)
Decay heat standard	= 1971 ANS decay heat standard (1.2 multiplier)
Mixing volume	= 50 percent Lower Plenum plus the core
Concentration of RWST	= 2600 ppm
Assumed axial power shape	= Uniform axial power distribution
Core generated steam	= 100 percent condensation

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 bottom peaked axial power distribution and 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 questioned the assumption that 100 percent of the core generated steam exiting the break was condensed and returned to the sump to reduce the sump boric acid concentration. Because the staff did not agree that all the core generated steam exiting the break would be condensed during recirculation, the licensee performed additional sensitivities over a range of effective condensation efficiencies from 0 percent to 100 percent. This reduced the precipitation time 1.2 hrs since the sump liquid concentration was no longer diluted with condensed vapor from the break. The staff analysis confirmed these subsequent sensitivities. The staff considers the assumption of 0 percent steam condensation efficiency from the break (which results in no long term dilution of the sump concentration) to be a critical analysis assumption. The 6.7-hour precipitation time provides more than 1 hour of margin for the EOP switch time for hot leg injection, which is 5.5 hours, and as such, the staff finds this analysis acceptable.

The PTN Units 3 and 4 ECCS consists of HHSI injected into the cold legs during the injection phase. Following drainage of the RWST, the HHSI flow is switched to the sump during recirculation. To control boric acid, the HHSI is switched to hot leg injection and all injection into the cold legs is terminated. For cold leg breaks, switch to hot leg injection occurs at 5.5 hours, which would preclude boric acid precipitation. However, for hot leg breaks, when the HHSI is switched to the hot legs and cold side injection is terminated (this action is required at 5.5 hours), boric acid begins to build-up. To control boric acid for hot leg breaks after the switch

is made to hot side injection, the HHSI needs to be recycled or re-aligned to all cold side injection. This realignment would be required 17 hours after opening of the break or 12.5 hours after the switch to hot leg injection at 5.5 hours. Again, since the break could occur in the hot or cold side, HHSI must be realigned back to the hot side injection at 33 hours, or 16 hours after the first recycling of HHSI. The HHSI would be alternately realigned every 16 hours thereafter to control boric acid for both hot and cold leg breaks. Analyses by the licensee showed that the recycling every 16 hours maintains boric acid below the precipitation limit. This recycling is required because realignment of the HHSI to hot leg injection precludes simultaneous injection into the cold legs.

During the realignment, ECCS injection into the RCS is terminated for 2 minutes. The licensee evaluated the consequences for small and large breaks and determined that a 3-minute interruption time in injection flow was insufficient to cause core uncovery and cladding heat-up. This was due to an excess of liquid in the vessel downcomer and upper plenum regions.

The licensee also documented that entrainment of the hot side injection would not occur after one hour using the Ishii-Grolmes entrainment correlation. This correlation applies to conditions where the liquid does not occupy a significant volume in the piping and viscosity does not dominate (the liquid phase is in the turbulent regime). While the correlation is similar to the Wallis-Steen correlation, use of the Ishii-Grolmes correlation extends the entrainment period when compared to the Wallis-Steen correlation. 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 5.5 hrs following opening of the break.

Because the control of boric acid requires operator action and attention to the timing, especially the recycling process discussed above, it is noted that the licensee confirmed through emergency exercises on the simulator that the realignment of HHSI was completed during all exercises in less than 2 minutes. The licensee calculated for the limiting large break LOCA using Appendix K assumptions at 5.5 hours post-LOCA, that the core would uncover in 3.77 minutes and set the maximum time to complete the realignment in the EOP at 3 minutes. The staff raised the concern that 0.77-minute margin was insufficient to accommodate operator error or equipment failure and actions to correct the failure. Additional calculations by the licensee showed that using realistic decay heat, core uncovery would occur after 7.3 minutes if injection is not reinstated, with the PCT reaching 2200 °F after an additional 20.5 minutes. This results in a maximum time 27.8 minutes to reach 2200 °F after terminating injection. The staff confirmed this result and also notes that this result is consistent with the timing to reach 2200 °F for plants with similar realignment procedures to control boric acid. Furthermore, the licensee also confirmed that the operators would be tested in accordance with the licensed operator training program to assure the staff that the operator action timing of less than 2 minutes for realignment of HHSI would be maintained and verified as part of the operator qualification and training program. With the operators performing the realignment in less than 2 minutes and the 27.8 minutes interruption timing to cause the PCT to reach 2200 °F, the staff finds there is sufficient time margin for the operators to successfully complete the realignment of HHSI at 5.5 hours to control boric acid build-up in the core. It is also noted that subsequent realignments beyond the initial 5.5-hour action time will have much larger delay times to cause PCTs to reach 2200 °F.

Conclusion

The NRC staff has reviewed the licensee's analyses of the LOCA events and the ECCS. The NRC staff concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and that the analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection system and the ECCS will continue to ensure that the peak cladding temperature, total oxidation of the cladding, total hydrogen generation, and changes in core geometry, and long-term cooling will remain within acceptable limits. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 4, 27, 35, and 10 CFR 50.46 following implementation of the proposed EPU. See the table in Section 2.8.5, Accident and Transient Analyses, Regulatory Evaluation to see the analogous GDCs applicable to the Turkey Point GDCs. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the ECCS and postulated LOCAs.

2.8.5.7 Anticipated Transients Without Scram

Regulatory Evaluation

Anticipated transient without scram (ATWS) is defined as an AOO followed by the failure of the reactor portion of the protection system specified in GDC-20. For Westinghouse plants, the regulation at 10 CFR 50.62 requires that each PWR must have equipment that is diverse from the reactor trip system to initiate the auxiliary feedwater system and initiate a turbine trip, both automatically, under conditions indicative of an ATWS. This equipment must perform its function in a reliable manner and be independent from the existing reactor trip system.

The NRC staff's review was conducted to ensure that (1) the above requirements are met, and (2) the setpoints for the ATWS mitigation system automatic circuitry (AMSAC) remain valid for the proposed, uprated conditions.

In addition, for Westinghouse plants, the NRC staff verified that the consequences of an ATWS are acceptable. The acceptance criterion is that the peak primary system pressure should not exceed the ASME Service Level C limit of 3200 psig. The peak ATWS pressure is primarily a function of the moderator temperature coefficient and the primary system relief capacity.

The NRC staff reviewed:

(1) The limiting event determination

(2) The sequence of events,

(3) The analytical model and its applicability

(4) The values of parameters used in the analytical model, and

(5) The results of the analyses.

The NRC staff reviewed the licensee's justification of the applicability of generic vendor analyses to its plant and the operating conditions for the proposed power uprate. Review guidance is contained in Matrix 8 of RS-001 and Chapter 15.8 of the Standard Review Plan.

NRC Technical Evaluation

The final ATWS rule, 10 CFR 50.62(c)(1), requires the incorporation of a diverse actuation of the AFW system and the turbine trip for Westinghouse-designed plants, The installation of the NRC-approved AMSAC design satisfied the rule. To remain consistent with the basis of the final ATWS rule, the peak RCS pressures predicted in the ATWS evaluation should be comparable to the peak RCS pressures reported for generic ATWS analyses,[147] conducted by Westinghouse in 1979, and must not exceed 3200 psig.

The limiting ATWS events, with respect to RCS pressurization, are the loss of load and loss of normal feedwater events. The licensee analyzed both of these postulated events. The staff accepts this approach since the licensee performed explicit analyses of both potentially limiting events.

The analyses were performed using the LOFTRAN code, since doing so is consistent with the Westinghouse analytic bases for compliance with the ATWS rule, and since RETRAN-02 is not NRC-approved for modeling PWR ATWS events.

The analyses assumed nominal thermal power, RCS T_{ave}, and RCS pressure. Nominal values are used because such assumptions are consistent with the PTN current licensing basis, and because ATWS is a beyond-design basis event. The staff finds the use of these nominal inputs acceptable because these postulated events are beyond the plant design basis.

The licensee assumed 0 percent steam generator plugging, based on the fact that generic sensitivity studies showed that 0 percent steam generator tube plugging results in the highest peak pressure. The analysis included AMSAC response time delays, as well as a delay to account for the time required for AFW pump run-up time, as well as sensor and logic delays. PTN-specific values for steam dump capacity and AFW were used, as well as an MTC that is bounding of 95 percent of cycle operations, consistent with the discussion contained in Section 3.2 of NS-TMA-2182 (see footnote 145).

The above assumptions are acceptable to the staff because they are, either, conservative, bounding, or reflective PTN-specific design. The 95 percent bounding MTC is acceptable because it is consistent with Westinghouse practice for analysis of the moderator temperature coefficient.

The results for the PTN-specific ATWS events are shown below:

Event	Loss of Normal Feed	Loss of Load
Peak Pressure	3160 psig	2946 psig
Limit	3200 psig	

[147] Anderson, T. M., Westinghouse Electric Corporation, "Anticipated Transients Without Scram for Westinghouse Plants," NS-TMA-2182, December 1979 (ML041130109).

For comparison, the generic studies for the loss of load event indicated that the peak pressure for a three-loop plant with 44-series steam generators should be approximately 2825 psia. Given the power uprate and smaller relief valves at PTN, the higher predicted peak pressure is expected.

Results provided by the licensee did not indicate any means to attain a long-term, shutdown state.[148] The licensee stated that indicated power in the plots for the analyses was non-zero due to decay heat, and that there are several means to attain long-term shutdown. These include safety injection initiation, emergency boration, normal boration, or a manual reactor trip. The staff accepts the licensee's response, since it indicates that there are multiple, diverse means to restore subcriticality and long-term shutdown following an ATWS event.

Based on the following considerations, the NRC staff finds the licensee's ATWS analysis acceptable in support of PTN EPU operations:

- The licensee performed plant-specific analyses of the limiting ATWS events reflective of uprated conditions,
- The analyses were performed consistent with generically approved analytic bases supporting the ATWS rule and using the NRC-accepted LOFTRAN code, and
- The licensee stated that the plant has an AMSAC system, which has been demonstrated to be compliant with 10 CFR 50.62 requirements.

Conclusion

The NRC staff has reviewed the information submitted by the licensee related to ATWS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on ATWS. The NRC staff concludes that the licensee has demonstrated that the AMSAC will continue to meet the requirements of 10 CFR 50.62 following implementation of the proposed EPU. The staff notes that the plant is not required by 10 CFR 50.62 to have a diverse shutdown system. Additionally, the licensee has demonstrated, as explained above, that the peak primary system pressure following an ATWS event will remain below the acceptance limit of 3200 psig. Therefore, the NRC staff finds the proposed EPU acceptable with respect to ATWS.

2.8.6 Fuel Storage

The licensee provided information regarding fuel storage in its EPU licensing report that was supplemented by a license amendment issued on October 31, 2011.[149] Based on issuance of this amendment, which addressed fuel storage at uprated conditions, the NRC staff did not consider fuel storage in the context of this EPU application except for the item discussed below.

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[148] Kiley, M. P., Florida Power and Light Company, letter to U.S. NRC, "Response to NRC Request for Additional Information Regarding Extended Power Uprate License Amendment Request Number 205 and Reactor Systems Issues. FPL Reference L-2011-305, Dockets 50-250 and 50-251, August 19, 2011. ML11234A178.
[149] Turkey Point, Units 3 and 4 – Issuance of Amendments re: Fuel Criticality Analysis (ML11216A057)

By letters dated November 9, 2011,[150] and December 22, 2011,[151] the licensee supplemented the EPU application proposed TS 5.5.1 and provided additional technical justification for the change, respectively. The supplement included revisions in the October 31, 2011, approval that were not included in the EPU application and added the parenthetical statement “or an equivalent amount of other burnable absorber.” The NRC staff had discussions with FPL to determine the acceptability of the request to add the parenthetical statement. By letter dated February 15, 2012,[152] the licensee withdrew its request to add the parenthetical statement due to the NRC staff needing further substantiating analyses. Also, FPL stated that Turkey Point, Units 3 and 4 will only credit Integral Fuel Burnable Absorber (IFBA) rods in the new fuel storage area, and by letter dated February 23, 2012, FPL submitted a commitment and has agreed to the following license condition:

> With respect to Technical Specification 5.5.1.3, FPL shall not credit any burnable absorber other than Integral Fuel Burnable Absorber (IFBA) for storage of fuel assemblies in the Region I spent fuel racks.

2.8.7 Additional Reactor Systems Review Areas

2.8.7.1 Natural Circulation Cooldown

<u>Regulatory Evaluation</u>

The ability for a nuclear power plant to cool down via natural circulation became an issue for all plants following the Three Mile Island accident. In its extended power uprate (EPU) request, FPL stated that analysis supports natural circulation cooldown capability for the current licensing and design basis. The NRC staff examination of the basis for this conclusion is summarized in the following paragraphs.

In follow-up to the Three Mile Island accident, the NRC issued Generic Letter 81-21,[153] which discussed a natural circulation experience at St. Lucie Unit 1 that resulted in steam formation in the reactor vessel upper head. As a result, the operators found it difficult to diagnose and control the reactor coolant system (RCS) in what was effectively a two pressurizer configuration. This delayed RCS depressurization and residual heat removal (RHR) initiation.

GL 81-21 requested licensees to provide an assessment of the following three items:

1. A demonstration (e.g. analysis and/or test) that controlled natural circulation cooldown from operating conditions to cold shutdown conditions, conducted in accordance with applicable procedures, should not result in reactor vessel voiding;

2. Verification that supplies of condensate-grade auxiliary feedwater are sufficient to support the cooldown method; and

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[150] ML11318A284
[151] ML11362A356
[152] ML12048A068
[153] “Natural Circulation Cooldown,” NRC Generic Letter No. 81-21, May 5, 1981.

3. A description of the training program and the procedural provisions (e.g. limited cooldown rate, response to rapid change in pressurizer level) that address the prevention or mitigation of reactor vessel voiding.

On March 28 and 29, 1985, tests at Diablo Canyon Unit 1 confirmed the ability of the plant to cool down under natural circulation conditions. Using these data, the Westinghouse Owners Group (WOG) developed empirical correlations to predict loop temperature differences and natural circulation mass flow rates for predicting plant behavior during these conditions.[154] NRC approval of WCAP-11095 is documented as discussed in a letter dated April 27, 1987, which includes an evaluation of the test results by Brookhaven National Laboratory.[155]

SRP Chapter 5, Branch Technical Position (BTP) 5-4, states that “the preoperational and initial startup test program ... shall include tests with supporting analysis to ... confirm that cooldown under natural circulation conditions can be achieved within the limits specified in the emergency operating procedures. Comparison with the performance of previously tested plants of similar design may be substituted for these tests.” BTP 5-4 also states that “operational procedures for bringing the plant from normal operating power to cold shutdown shall ... include specific procedures and information required for cooldown under natural circulation conditions. These natural circulation cooldown procedures and analyses should consider the potential for a voiding event in the reactor vessel head and incorporate appropriate controls to address such an occurrence.” Also, taking the plant to cold shutdown is required to be accomplished in a “reasonable time” “for cooldown under natural circulation.”[156] Regulatory Guide 1.33 is referenced with respect to applicable procedures.

<u>NRC Technical Evaluation</u>

The PTN licensee provided the following discussion that is applicable to the above background:

> While there are no explicit criteria for this evaluation, the following are reasonable criteria to show acceptable natural circulation cooldown behavior:
>
> - The natural circulation ΔTs (temperature differences) and temperatures should be reasonable (i.e., bounded by full-power conditions). This helps to avoid any concerns with thermal stresses and also helps to ensure adequate reactor coolant system (RCS) subcooling;
>
> - The Steam Generator (SG) Atmospheric Dump Valves (ADVs) should be capable of cooling down the plant to Residual Heat Removal (RHR) system cut-in conditions (PRCS [primary reactor coolant system] < 450 psig and Tavg < 350°F) within a reasonable time. Allowing for 4 hours at hot standby and an emergency operating procedure (EOP) maximum

[154] Westinghouse Electric Company, “Diablo Canyon Units 1 and 2 Natural Circulation/Boron Mixing/Cooldown Test Final Post Test Report-Cold Shutdown,” WCAP-11095, March 1986.
[155] Zwolinski, John A., “Results of the Diablo Canyon Unit 1 Natural Circulation, Boron Mixing, and Cooldown Test Evaluation,” NRC letter, ML073540832, April 27, 1987.
[156] BTP 5-4 was not backfitted to the Turkey Point plants. However, PTN stated that it would be "consistent with NRC recommendations contained" in BTP 5-4.

cooldown rate of 25°F/hour for natural circulation, the time frame for RHR cut-in should be on the order of 12 to 14 hours; and

- Compare the hydraulic flow coefficients with those of Diablo Canyon. PTN procedural guidance for natural circulation cooldown follows the NRC-approved WOG Emergency Response Guidelines (ERGs).

PTN provided information pertinent to its existing capability and NRC approvals associated with plant license renewal in 2002 and it provided the following with respect to updating the UFSAR to reflect EPU conditions:

> The design and licensing basis in UFSAR Section 9.11 and TS 3/4.7.1.3 Bases will be revised to reflect CST [condensate storage tank] storage capacity capable of supporting a 4-hour hold at hot standby conditions followed by a 9-hour natural circulation cooldown with at least one CRDM [control rod drive mechanism] fan in operation to the RHR cut-in conditions consistent with NRC recommendations contained in the Standard Review Plan (SRP) Branch Technical Position (BTP) 5-4. This evaluation will demonstrate the ability to cool down the plant on natural circulation to RHR cut-in conditions (P_{RCS} < 450 psig and T_{avg}< 350°F).

The PTN licensee discussed its evaluation of EPU effects related to natural circulation cooldown by using the WOG ERG methodology to estimate flow rates and core delta temperatures using core and system hydraulic flow coefficients. It compared hydraulic flow coefficients between PTN and Diablo Canyon and showed that natural convection flow would progress more rapidly at PTN. The cooldown evaluation considered the EPU decay heat, and a cooldown from hot shutdown conditions, with 4 hours at hot standby, followed by cooldown to RHR cut-in conditions. It included an assessment of ADV capability relative to steam generator shell side saturation conditions, correlated with primary system temperature. Results were consistent with natural circulation cooling capability at about 6 percent thermal power, illustrating that, once started, natural circulation will remove decay heat following reactor trip. Calculated loop ΔT at 3 percent power was 38.9 °F which was comparable to a measured ΔT of 36 – 40 °F at an unidentified three loop plant. Condensate from the condensate storage tank was stated to be adequate for the cooldown. Assumed decay heat generation rates were comparable to maximum values typically used for design basis analyses.

Several clarifications were addressed by NRC's Reactor Systems Branch (SRXB) questions, PTN's responses,[157, 158] and SRXB's assessment. These are summarized in the following discussion.

Licensing Report Section 2.8.7.2 states that a minimum subcooling margin of 50 °F is maintained during natural circulation cooldown until RCS temperature is below 350 °F. The staff requested that the licensee explain what temperature sensors are used to determine RCS temperature and where they are located within the RCS.

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[157] ML11137A080.

[158] Kiley, Michael, Florida Power and Light, "Response to NRC Request for Additional Information Regarding Extended Power Uprate License Amendment Request No. 205 and Reactor Systems Issues," FPL Reference L-2011-369, Dockets 50-250 and 50-251, September 16, 2011. ML11263A003.

In response, the licensee stated that subcooled margin during a natural circulation cooldown is monitored using the core exit thermocouples (CETs). The CETs are terminated in the upper support column.

CETs provide temperature immediately above the core and are the best temperature indication for monitoring subcooling and core cooling although they will not completely cover upper head temperature under the transient conditions associated with natural circulation cooling. Hot and cold leg temperatures are also necessary to monitor natural circulation progress. Within the scope of the question, monitoring by the CETs for determination of subcooling margin is acceptable.

The staff requested that the licensee explain what is used to determine maximum upper head temperature during natural circulation cooldown. The staff also requested that the licensee compare the upper head temperatures predicted to exist during natural circulation cooldown for the existing power level and the proposed power level, and include saturation temperature at the uppermost upper head elevation in the comparison.

In response, the licensee stated that upper head temperature values were not directly calculated in the natural circulation cooldown analysis and, therefore, are not available to present in chart or tabular format.

The WOG performed analyses of natural circulation cooldown for Westinghouse 2, 3, and 4 loop plants to prevent void formation in the upper head. The resulting cooldown rate limits were incorporated into the WOG ERGs, which provides the guidance for creating plant specific EOPs. To ensure the temperature of the upper head does not significantly deviate from the RCS, the RCS cooldown rate is limited to 25 °F/hr by the EOPs for natural circulation cooldown.

During a natural circulation cooldown one of the primary means of heat removal from the upper head and associated fluid is through the use of control rod drive mechanism (CRDM) cooling fans. For the proposed increased power level, the heat removal ability of the CRDM fans is unaffected and can adequately cool the upper head as shown in LR Section 2.8.4.1.2. Using the bounding values provided in the generic analysis, the heat removal rate provided only by CRDM cooling fans is 21 °F/hr at transient start and decreases to 11 °F/hr when the upper head is cooled to 350 °F. An additional upper head cooldown rate of 10 °F/hr is provided by the 25 °F/hr RCS natural circulation cooldown rate. Therefore, the minimum total upper head cooldown rate is approximately 21 °F/hr which ensures that the upper head temperatures do not significantly deviate from that of the RCS.

Licensing Report Section 2.8.4.1.3.1 identifies the increased heat load on the CRDM due to the EPU and discusses a recent modification as part of the reactor head replacement projects. Exit air temperature is currently limited to below 170 °F and will be increased to 180 °F for EPU conditions. The EPU is predicted to increase temperature of several head components by a proprietary amount. The increased temperature remains below the specified limit of 392 °F. Further, the EPU is predicted to increase the inlet to the cooling units from a value below 170 °F a value below the apparently new specified limit of 180 °F, which is stated not to “have any detrimental effects on the function of the CRDMs, or the longevity of the coils."

Assuming the PTN conclusions are correct that the increased temperatures are acceptable, the information supports a conclusion that the CRDM fans can adequately cool the potentially affected components during normal operation. Upper head temperature behavior is discussed below.

The licensee states that "Table 2.8.7.2-4 ... shows ... T_{avg} decreases at approximately 25 °F/hr as prescribed in the EOPs to insure head voiding doesn't occur." Table 2.8.7.2-4 illustrates cooldown at 1 hour with T_{ave} = 585 °F. This corresponds to T_{ave} = 610 °F at reactor trip at a cooldown rate of 25 °F/hr; somewhat less than the vessel outlet temperature of 616.8 °F in Table 2.8.3-1. The staff requested that the licensee describe the reason for the difference in temperatures at the time of reactor trip.

As discussed in the EPU Licensing Report (LR), Section 2.8.7.2, the natural circulation cooldown analysis assumes an initial 4-hour hold at hot standby conditions before commencing the 25 °F/hr cooldown. Thus, the licensee clarified, the 610 °F should not be taken as the initial T_{avg} based on a reported T_{avg} of 585 °F at 1 hour. (For the proposed power level, T_{avg} at 100 percent power is 587 °F.) Values in LR Table 2.8.7.2-4 for hour 1 are values equal to 1 hour after reactor trip. At time of reactor trip the analysis conservatively assumed T_{hot} equal to the maximum full power core exit temperature of 620.8 °F (versus the vessel outlet temperature of 616.8 °F); this is displayed in LR Table 2.8.7.2-1. Per LR Table 2.8.7.2-4, at 1 hour after reactor trip, ΔT through the core will decrease to a value of 24.08 °F, and T_{hot} would correspond to a value of 597.04 °F. This equates to about a 24 °F drop in hot leg temperature in the first hour while T_{avg} remains relatively stable as described above.

Based on the clarification described above, the staff finds that the differences in water temperature are acceptably addressed.

Regarding the Diablo Canyon natural circulation test, the safety evaluation for WCAP-11095 stated that "the acceptance criterion for the upper head bulk water temperature was that a 50 °F subcooling margin be maintained during cooldown and depressurization. A 100 °F difference between the core average exit temperature and the upper head bulk water temperature was imposed as an administrative limit." This objective was met with a 20 °F/hr cooldown rate and three CRDM cooling fans.[159] The maximum temperature difference between the RCS and upper head was 40 °F. No upper head voiding occurred. Figure 4.1 of Reference 3 showed that the subcooling margin initially increased over the duration of the cooldown for a 20 °F/hr cooldown rate and paralleled the cooldown rate with about 40 °F subcooling margin after five hours of beginning of cooldown.[160] If CRDM fans were not operating, subcooling margin was not retained unless cooldown rate was reduced.

[159] The fans were necessary to maintain CRDM temperatures within acceptable limits.

[160] The SER approving WCAP-11095 also stated "While the staff considers natural circulation cooldown without voids as more desirable, cooldown with voids may be acceptable provided it can be accomplished using only safety grade equipment (including adequate instrumentation), approved procedures, and the operators have adequate training in the use of these procedures."

PTN identified two contributors to upper head cooling, (1) the CRDM cooling fans that provide 21 °F/hr at transient start and decrease to 11 °F/hr when the upper head is cooled to 350 °F, and (2) an upper head cooldown rate of 10 °F/hr that is provided by the 25 °F/hr RCS natural circulation cooldown rate. PTN concluded that the minimum upper head cooldown rate is approximately 21 °F/hr and the rate is more rapid immediately after reactor trip as illustrated by the initial CRDM cooling fan contribution of 21 °F/hr in combination with an approximately 24 ºF decrease in hot leg temperature in the first hour following reactor trip. Since the minimum head cooldown rate will be at least approximately the same as the bulk of the RCS water, one may conclude that the temperature difference between the head and the RCS water will not increase during the cooldown. On the basis of the above information, the NRC staff concludes that predicted PTN head cooling behavior is consistent with the Diablo Canyon results and subcooling margin will be retained if CRDM cooling fans are operating.

The staff requested that the licensee provide representative RCS natural circulation temperatures that have been observed during operation of the PTN plant and compare these to selected natural circulation temperatures provided in Licensing Report Section 2.8.7.2.2.3.

In response, the licensee stated that, since the PTN stretch power uprate in 1996, there have been multiple unit trips including a dual unit trip on February 26, 2008, but no cases of a natural circulation cool down from full power to RHR system entry conditions (350 ºF). There was only one case of a partial natural circulation cooldown which occurred on October 31, 2005, while Unit 4 was in Mode 3 at 400 °F to the RHR system entry conditions. This cooldown event took place over 6 hours or more and was punctuated by variable cooldown rates such that actual plant performance data would not be representative of data provided in LR Section 2.8.7.2.2.3.

Since the data does not exist, the staff finds the response acceptable.

Finally, the staff asked the licensee the following question: Is the Table 2.8.7.2-1 620.8 °F core outlet temperature an average value or the peak value located immediately above the hottest region of the core?

The licensee responded that the core outlet temperature of 620.8 °F is the average temperature of the water directly exiting the core. After this water gets mixed with the flow which bypasses the core, the temperature of the water which enters the hot leg is reduced. The maximum average hot leg temperature established for EPU conditions is 616.8 °F. This is provided in LR Table 1.1-2.

The staff finds that the licensee clarified the information presented, and on that basis, finds that the RAI response is acceptable.

Conclusion

FPL evaluated the impact of its requested power uprate on the capability of PTN 3 and 4 to cool down via natural circulation. The NRC staff finds FPL's evaluation of natural circulation cooldown acceptable because it follows Westinghouse Owners Group Emergency Response Guidelines methodology, it has been acceptably compared to tests, it demonstrates acceptable loop differential temperatures will be achieved during natural circulation, and support is provided to show that subcooling margin is retained at a 25 °F/hr cooldown rate provided control rod drive

mechanism cooling fans are operating. The NRC staff finds the proposed power uprate acceptable with respect to natural circulation cooldown.

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

The Nuclear Regulatory Commission (NRC) staff reviewed the radioactive source term associated with the extended power uprate (EPU) 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 PTN FSAR related to liquid waste management systems and gaseous waste management systems. The NRC staff's acceptance criteria for source terms are based on (1) 10 CFR Part 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas; (2) 10 CFR Part 50, Appendix I, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" criterion; and (3) 10 CFR Part 50, Appendix A, 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 NRC's NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (Standard Review Plan or SRP), Section 11.1.

NRC 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 nonradioactive 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," 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 PTN. 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 determined that the licensee used conservative assumptions regarding the source terms and system decontamination factors to derive the proposed parameters and resultant composition and quantity of radionuclides 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 radioactive 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:

1. Loss-of-Coolant Accident
2. Main Steamline Break
3. Steam Generator Tube Rupture
4. Locked Rotor Accident
5. Rod Cluster Control Assembly Ejection
6. Fuel Handling Accident
7. Waste Gas Decay Tank Rupture
8. Spent Fuel Cask Drop

The licensee's review for each accident analysis included (1) the sequence of events and (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 AST are based on:

- 10 CFR 50.67, insofar as it describes reference values for the exclusion area boundary (EAB) and the outer boundary of the low population zone (LPZ) 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 (CR) under accident conditions without personnel receiving radiation exposures in excess of 5 roentgen equivalent man (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.

NRC Technical Evaluation

The licensee's current licensing basis (CLB) AST accident analyses were performed at EPU conditions. By letter dated June 23, 2011,[161] these analyses were reviewed and approved by the NRC staff as Turkey Point, Unit 3 and Unit 4, Amendment Nos. 244 and 240, respectively. The analyses included several plant modifications including (1) the relocation of the CR emergency ventilation system (CREVS) dual air intakes to areas beyond the northeast and southeast corners of the auxiliary building, (2) upgrading the CREVS emergency fan motors, (3) the installation of a new compensatory filter unit as a backup to the existing CREVS filter train, (4) the addition of manual isolation dampers in the kitchen and lavatory exhaust ducts, (5) the implementation of revised CREVS TS 3/4.7.5 to provide better specification of system operability requirements, and (6) the installation of a new passive containment sump pH control system consisting of ten stainless steel mesh baskets filled with sodium tetraborate (NaTB) at the bottom of each reactor containment. These modifications are necessary to support AST implementation and will be installed and placed in service prior to AST implementation at PTN.

Since the CR emergency air intakes had not been relocated at the time of issuance of AST Amendment Nos. 244 and 240, the associated CR atmospheric dispersion factors (χ/Q values) used as inputs to the CR dose assessment were based upon intended design locations. Implementation of the AST is contingent upon several License Conditions, including License Conditions 3.H.1 and 3.I.1 of AST Amendment Nos. 244 and 240, respectively. These License Conditions state, in part, that FPL would provide to the NRC a confirmatory assessment which demonstrates that the requirements of 10 CFR 50 Appendix A, GDC 19 will be met for the locations at which the CREVS intakes were installed. The confirmatory assessment would

[161] ML110800666

follow the methodology in AST Amendment Nos. 244 and 240, including the methods used for the establishment of the χ/Q values.

By letter dated August 11, 2011,[162] FPL provided "Confirmatory Dose Assessment for Control Room Emergency Ventilation System Air Intake Modification to Satisfy Operating License Conditions 3.H.1 for DPR-31 and 3.I.1 for DPR-41" (hereafter in this section referred to as the Attachment). As stated in the Attachment, during relocation activities, the licensee encountered construction interferences that resulted in the need to install the emergency air intakes at locations different than those identified in the assessment to support Amendment Nos. 244 and 240. As a result, FPL recalculated the CR X/Q values, resultant dose consequences, and provided a summary of the reassessment. The licensee stated that, although the southeast emergency air intake is still considered limiting for the dose analyses, the actual differences in χ/Q values for the two air intakes is now much closer. Further, the northeast air intake was identified as the limiting case for a postulated release from the Unit 3 spent fuel building. Tables 1 and 2 of the Attachment list the resulting CR χ/Qs, revised integrated 30 day control room radiological doses, and the dose differences from those used to support Amendment Nos. 244 and 240. The net impact of the changes on the radiological dose consequences was a small increase in the integrated CR dose except in the cases of LOCA, FHA, and RCCA Ejection - Containment Release, where the dose consequences decreased.

The NRC staff qualitatively reviewed the revisions to the inputs used by FPL in the updated CR χ/Q value assessment and found the identified changes to be generally consistent with site configuration drawings and staff practice. The staff also performed a sample of confirmatory calculations and has concluded that the licensee's χ/Q values listed in Table 1 of the Attachment are acceptable for use in the CR design basis accident dose assessment associated with License Conditions 3.H.1 and 3.I.1. 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 during review of the AST LAR. NRC staff considers that the updated CR χ/Q values associated with the locations of the emergency air intakes, as installed, supersede the CR χ/Q values in the AST SE associated with Amendment Nos. 244 and 240.

In addition, AST Amendment Nos. 244 and 240 contain License Conditions pertaining to the installation of a new compensatory filter unit as a backup to the existing CREVS filter train and the installation of a new passive containment sump pH control system consisting of ten stainless steel mesh baskets filled with sodium tetraborate (NaTB) at the bottom of each reactor containment. Therefore prior to implementation of the EPU, the license conditions associated with AST Amendment Nos. 244 and 240 must be completed.

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 of this SE. NRC staff considers that the updated CR χ/Q values associated with the locations of the emergency air intakes, as installed, supersede the CR χ/Q values in the AST SE associated with Amendment Nos. 244 and 240. The NRC staff finds that the licensee's estimates of the EAB, LPZ, and CR doses will comply with these guidelines as documented in the staff's SE

[162] ML091250564

dated June 23, 2011, as revised by changes provided in the Attachment in support of License Conditions 3.H.1 and 3.I.1 of AST Amendment Nos. 244 and 240. Therefore, the NRC staff finds with reasonable assurance that PTN, 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.

2.10 Health Physics

2.10.1 Occupational and Public Doses

Regulatory Evaluation

The Nuclear Regulatory Commission (NRC) staff reviewed the effects of the proposed EPU on both occupational and public radiation doses. The NRC staff also reviewed the licensees LAR to ensure that any dose increases will be maintained within applicable regulatory limits and are as low as is reasonably achievable (ALARA).

The NRC staff's review included an evaluation of expected increases in radiation levels and how this would affect plant area dose rates, plant radiation zones, and plant area accessibility. The NRC staff evaluated how occupational doses would be affected when access is needed to plant vital areas following an accident. The NRC staff also considered the effects that the proposed EPU would have on public radiation doses from increases in plant effluent levels and direct radiation levels.

The NRC's acceptance criteria for occupational and public radiation doses are based on Title 10 of the *Code of Federal Regulations* (10 CFR) Part 20, "Technical Specifications," and 10 CFR Part 50, Appendix I. Specific review criteria are contained in NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (Standard Review Plan, SRP), Sections 12.2, 12.3, 12.4, and 12.5, NUREG-0737, " Clarification of TMI Action Plan Requirements," Item II.B.2, and other guidance provided in Matrix 10 of the NRC Review Standard (RS)-001, "Review Standard for Extended Power Uprates," December 2003.

NRC Technical Evaluation

Radiation Sources

In general, the production of radiation and radioactive material (from fission and activation products) in the reactor core is directly dependent on the neutron flux and power level of the reactor. The increased flux will cause an increase in the fission product inventory in the core and in spent fuel. The increased flux will also cause an increase in the neutron activation products in the reactor coolant system, control rod assemblies, reactor internals, and the pressure vessel. During operations, the increased flux will also result in an increase in neutron and gamma flux leakage out of the reactor vessel.

Depending on the number of fuel defects, an increased inventory of fission products in the core would also increase the fission product concentration in the reactor coolant. An increase in the

reactor coolant system radioactivity concentrations would also increase the radiation levels in the auxiliary building and other buildings where reactor coolant is contained. In addition, the radioactivity concentration in the secondary system may also increase due to primary to secondary leakage in the steam generators (SG). Therefore, an approximate 15 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 throughout the plant.

The technical specifications (TSs) limit the reactor coolant dose-equivalent Xe-133 and dose-equivalent I-131 activity to the original design basis values.

Radiation Levels

The LAR states that there will be an approximate 15 percent increase in radiation source term and radiation levels in the containment building, auxiliary building, intermediate building, and turbine building where reactor coolant is present. The licensee has utilized scaling techniques and updated its shielding analysis to determine the impact of the EPU on plant radiation levels in the major plant areas.

During reactor operation, the radiation dose rates near the reactor vessel (RV) are primarily the result of neutron and gamma leakage flux from fission reactions in the core. During shutdown, radiation dose rates are primarily the results of radioactive emissions from radioactive decay of fission products in the core, and activation products 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 radiation fields near the RV. The licensee estimates by scaling techniques that the normal operational radiation levels near the RV will increase by a factor of approximately 15.3 percent. However, in performing new shielding design calculations using computer-based modeling, the licensee has determined that the neutron and gamma leakage from the RV is significantly less than conservatively estimated in the original design basis calculations. NRC staff reviewed the licensee's analysis and determined that the updated methods of analysis uses were an appropriate method of reanalysis. Although the neutron and gamma flux levels will increase by 15 percent as a result of the EPU, increases in radiation levels near the reactor vessel will not be substantially greater than the radiation levels previously evaluated and approved in the original design basis analyses.

During power operations, the radiation dose rates in the reactor building in general work areas are determined primarily by the neutron dose rates and the N-16 levels in the reactor coolant. During shutdown conditions, the dose rates in these areas are determined primarily by the deposited fission and activation product activity in the RCS and the SG components. The licensee estimates that, following EPU, the neutron, N-16 and fission and activation product source terms will increase by approximately 15.3 percent, resulting in operating and shutdown radiation levels in these areas increasing by the same percentage. In areas outside containment (e.g., auxiliary building), the radiation sources are fission products and activation products in down-stream sources originating from the primary coolant activity. The licensee estimates that, following EPU, both the fission products and the activation products will increase by approximately 15 percent, resulting in an approximate 15 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 15 percent. Therefore, the normal operational radiation levels in most of the plant areas are expected to increase by approximately 15 percent. The licensee has stated that this expected increase in radiation levels will not significantly affect radiation zoning, occupancy limits, or shielding requirements because of the radiation protection programs and the conservatism in the licensee's shielding analyses.

The site radiation protection and ALARA programs required by 10 CFR 20.1101 will be used to ensure compliance with the occupational dose limits of 10 CFR Part 20. Radiation protection personnel will monitor radiation levels in the affected areas of the containment, auxiliary building, and turbine building during the initial power ascension following the proposed EPU. They will also perform radiation surveys of specific plant areas where dose rates would be most likely to change following the EPU. The licensee will also use existing containment area radiation monitors and airborne radioactivity monitor readings to provide an early warning of any abnormal dose rates in containment. The licensee will use the data gathered from these surveys to assure that all radiation areas are properly designated, posted, and controlled, in a timely manner, as required by 10 CFR Part 20 and the technical specifications.

The licensee estimates that the annual collective dose at Turkey Point Nuclear Plant (PTN) will increase by approximately 15 percent as a result of implementing the proposed EPU. However, with the use of the ALARA program, as discussed below, the NRC staff has reasonable assurance that the licensee will continue to meet the 10 CFR 20.1101 ALARA requirements and all occupational dose limits.

Under accident conditions, Item II.B.2 of NUREG 0737 states that the occupational worker dose guidelines of 10 CFR Part 50, Appendix A, GDC-19 shall not be exceeded such that operators can access and perform required duties and action in designated vital areas. 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 total effective dose equivalent (TEDE) for licensees that have adopted the alternate source term under 10 CFR 50.67. PTN has been approved for use of alternate source terms for post accident dose assessments associated with onsite locations that require continuous occupancy such as the control room (CR) and the technical support center (TSC). NRC staff assessed the increased radiation in the CR, TSC, and vital areas and verified that although radiations levels are increasing by 15 percent, occupational doses under accident conditions will remain within the 5 rem TEDE limit and GDC 19 requirements. The NRC staff concludes that on the basis of information contained in the licensee's submittal regarding post EPU radiation levels, PTN will be capable of meeting the occupational dose limits in accordance with the criteria in SRP Section 12.4 and NUREG-0737, Item II.B.2.

Ensuring that Occupational and Public Radiation Exposures are ALARA

The radiation protection program at PTN ensures that internal and external radiation exposures to station personnel, contractor personnel and the general population resulting from station operation will be within applicable regulatory limits and will be ALARA. Design features currently in place at PTN to support the plant'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. The design features currently in place at PTN 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, including ALARA requirements.

Public and Offsite Radiation Exposures

The technical specifications (TS) for PTN incorporate the numerical guides for design objectives of 10 CFR Part 50, Appendix I for the annual dose to an individual in an unrestricted area. At the original rated power, the radiation effluent doses were a small fraction of the doses allowed by TS limits. For liquid effluents, the licensee estimates that the radioactivity content will increase by a maximum of 15.3 percent as a result of the EPU. With this increase, the projected public doses from liquid effluents following EPU will still meet the TS limits and the Appendix I Design Objectives.

For gaseous effluents, the licensee estimates the noble gases and tritium releases will be bounded by a maximum of 17.1 percent increase, while the particulate and iodine category will be bounded by a maximum 25.3 percent increase (due to the large increase in moisture carryover due to the EPU). With these increases, projected doses from gaseous effluents following EPU will continue to meet the TS limits and the 10 CFR Part 50, Appendix I, "Design Objectives." In addition, the licensee will continue to perform periodic verifications to assure that annual Appendix I design objectives are being met.

For direct radiation, solid radioactive waste is stored onsite that could potentially affect the offsite radiation dose. The offsite doses are limited by the 40 CFR Part 190 regulations to 25-millirem whole body dose from all sources in the nuclear fuel cycle, including direct radiation from the facility. The licensee does not expect that the plant will generate substantial additional radioactive waste volumes that will need to be processed by the radioactive waste systems as a result of the EPU. The level or amount of radioactivity in the waste is expected to increase by 17.7 percent. However, the amount of dose to members of the public from direct radiation is expected to continue to be negligible with the increased radioactivity of the stored radioactive waste. Additionally, the direct radiation component of the offsite dose will be monitored using environmental dosimeters as described in the Offsite Dose Calculation Manual. The NRC reviewed the licensee's calculation models and assessments and concludes that methods used in making these assessments were adequate and reasonable.

On the basis of information contained in the licensee's submittal regarding public and offsite radiation exposures, the NRC staff concluded that, 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. Ongoing monthly and quarterly surveillances required by the Offsite Dose Calculation Manual ensures that radioactive discharges are within limits and that public exposures are 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 as low as is reasonably achievable. 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 Nuclear Regulatory Commission (NRC) staff reviewed the licensee's human factors evaluation to confirm that changes made to implement the proposed extended power uprate (EPU) will not adversely affect operator performance. The staff reviewed changes to operator actions, human/system interfaces, procedures, and training identified by the licensee as needed for the proposed EPU. The NRC's acceptance criteria for human factors are based on General Design Criterion 19 (GDC-19) of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants," 10 CFR 50.120, 10 CFR 55, and the guidance in Generic Letter (GL) 82-33. Specific review criteria are contained in NRC's NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (Standard Review Plan or SRP), Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0, and RS-001, "Review Standard For Extended Power Uprates."

NRC Technical Evaluation

The NRC staff has developed a standard set of topics for the human factors assessment of EPUs, i.e., RS-001, Section 3.3, "PWR [Pressurized Water Reator] Template Safety Evaluation," Insert 11. Florida Power and Light Company (FPL, the licensee) has addressed these topics in its submittal. 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 identified in its license amendment request (LAR) the following changes:

Minor changes:

The licensee identified many editorial or setpoint changes to procedures, that were too numerous to list individually. However, they provided examples of "minor" changes and stated that the changes "have been evaluated for time critical operator actions and it has been

determined that they have no impact on the time available to perform critical operator actions, critical steps or operator actions in the emergency, abnormal and other operating procedures." Based on these statements, the staff finds these proposed minor changes to the procedures to be acceptable.

Significant changes:

The licensee's position is that the significant changes to the Turkey Point Nuclear Plant (PTN) emergency operating and contingency action procedures (listed below) do not alter basic event mitigation strategies. The changes will be implemented using the normal PTN procedure change control process, and the operators will receive appropriate classroom and simulator training prior to EPU implementation.

Procedure EOP [Emergency Operating Procedure]-ES-1.3, "Transfer to Cold Leg Recirculation," will be changed to direct the use of two high head safety injection (HHSI) pumps (previously one HHSI pump) during cold leg recirculation. The licensee estimated that the addition of an action to start a second HHSI pump adds 10 seconds to this action sequence. Simulator validation of the one pump configuration demonstrated that the action sequence takes less than 2 minutes. Adding 10 seconds will still allow sufficient time to complete the action sequence. This assumption will be confirmed when the procedure changes are verified and validated in accordance with the plant procedure for emergency and off-normal operating procedures verification and validation.

Procedure EOP-ES-1.4, "Transfer to Hot Leg Recirculation," will be changed to direct the use of two HHSI pumps (previously one HHSI pump). As with cold leg recirculation, the licensee estimated that the addition of an action to start a second HHSI pump adds 10 seconds to this action sequence. Additionally, the new procedure step will change the time limit that HHSI flow can be interrupted during switchover to hot leg recirculation from 10 to 3 minutes. Simulator validation of the one pump configuration demonstrated that the action sequence takes less than 2 minutes. Adding 10 seconds will still allow sufficient time to complete the action sequence. This assumption will be confirmed when the procedure changes are verified and validated in accordance with the plant procedure for emergency and off-normal operating procedures verification and validation

Because simultaneous hot and cold leg recirculation will not be conducted under EPU, Attachment 1, "Concurrent Cold Leg and Hot Leg Recirculation," will be removed from the Procedure EOP-ES-1.4.

The changes identified above will be incorporated in compliance with the FPL plant procedure change control program, including verification and validation of the operators' capability to perform the actions reliably and within the time available. These procedure changes and the associated training will be implemented prior to operation at uprated conditions. Therefore, the staff finds these proposed actions to be acceptable.

Operator Actions Sensitive to Power Uprate

The licensee stated that there are no operator actions (other than those described above, Emergency and Abnormal Operating Procedures) affected by the proposed EPU. Additionally,

there are no operator workarounds created as a result of EPU. The staff finds the licensee's statements to be acceptable.

Changes to Control Room Controls, Displays, and Alarms

This section includes the review of any changes that the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms.

FPL stated in its LAR that changes to the PTN control room controls and displays would not be extensive and will generally include calibration and/or rescaling loops for identified instrumentation.

The licensee states that the following instrumentation loops are affected by EPU:

- Units 3 and 4, main steam flow (calibration range, scaling, replace indicator scale plates, update indicator banding).

- Units 3 and 4, turbine 1st stage pressure (calibration range, scaling, replace indicator scale plates, update indicator banding).

- Units 3 and 4, electro-hydraulic control turbine controls upgrade (replace existing control system with installation of a new high pressure electro-hydraulic control system and electronic governor).

- Units 3 and 4, reheater steam to low pressure turbine pressure (update banding).

- Units 3 and 4, steam generator feedwater flow (calibration range, replace indicator scale plates, update indicator banding).

- Units 3 and 4, power block instrumentation will be addressed during the main generator replacement modification. The following instruments are affected:
  - gross megawatt meter
  - gross megawatt recorder
  - watt-hr meter
  - generator Var meter
  - generator megawatt meter
  - generator phase ampere meters

Additionally, procedures and plant computer data associated with these changes will be revised as necessary to be consistent with the new operating parameters and instrument channel rescaling described above.

Training related to the EPU modifications and resulting control board and procedure changes will be provided to the operators. The operators will also be provided station modification review packages as well as classroom and simulator training where appropriate. The staff finds these actions to be acceptable.

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. Any changes identified to the safety parameter display system will be captured through the normal update process, modification process, and interdepartmental reviews. 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 it will ensure that adequate training is provided prior to EPU implementation per its normal training program. The proposed training will focus on the Technical Specification changes, procedure changes and plant modifications, and will take place during the training cycle prior to the outage implementing the EPU modifications.

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 FPL's approach to training and simulator upgrading acceptable.

Conclusion

The NRC staff has reviewed the licensee-identified changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that FPL has: (1) appropriately accounted for the effects of the proposed EPU on their personnel and (2) taken appropriate actions to ensure that operator performance is not adversely affected by the proposed EPU. Therefore, the NRC staff finds the licensee's proposed EPU acceptable regarding the human performance 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 extended power uprate (EPU) test program is to demonstrate that structures, systems and components (SSCs) will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The Nuclear Regulatory Commission (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 Title 10 of the *Code of Federal Regulations* (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 Regulatory Guide 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 anticipated operational occurrences (AOOs); and specific review criteria contained in Section III, "Review Procedures," of the NRC's NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (SRP or Standard Review Plan) Section 14.2.1 (SRP 14.2.1). Other guidance is also provided in Section 2 and Insert 12 for Section 3.3, "PWR [Pressurized Water Reactor] Template Safety Evaluation," of the NRC review standard, RS-001, "Review Standard for Extended Power Uprates, " (December 2003).

NRC Technical Evaluation

SRP 14.2.1, Section III.A, Comparison of Proposed EPU Test Program to the Initial Plant Test Program

This Section of the SRP specifies the guidance and acceptance criteria which the licensee should use to compare the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison should include: 1) all initial power-ascension tests performed at a power level of equal to or greater than 80 percent original licensed thermal power (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 4, “Licensing Report,” of the license amendment request which discusses the analyses and evaluations performed, in accordance with staff guidance in RS-001, 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 1.0-1, of Section 1.0, “PTN [Turkey Point Nuclear Plant] Unit 3 and 4 Power Uprate Key Planned Modifications,” which provided a discussion of the key modifications planned for EPU implementation. The planned modifications listed in the table, which do not constitute regulatory commitments, will be implemented in accordance with the requirements of 10 CFR 50.59. Table 2.12-5, “Plant Modification Testing for Unit 3 and Unit 4,” provided functional and operational post modification testing planned for each modification to verify satisfactory installation and performance. Some tests that are considered in the verification of the plant integrated response to transients are also listed in the table. The LR also provided in Section 2.12.1.2.3 a discussion of the EPU testing planned and provided a comparison of initial startup and EPU testing, including justification for not performing certain large transient testing.

The staff also found that transient tests described in the initial startup test program were listed in Table 2.12-3, “Comparison of Proposed EPU Tests to Original Startup Tests,” of Attachment 4. The Table provided a summary of the original startup testing, a brief comparison with the proposed power ascension and testing plan (PATP), and a justification for not repeating several of the original tests during the proposed EPU test plan. Table 2.12-1, “PTN Extended Power Uprate Power Ascension Test Plan,” of Attachment 4, provided a discussion of power ascension startup tests initially performed at 80 percent OLTP or greater. With respect to large transient testing, the licensee provided Table 2.12-2, “Large Plant Transient Tests in Turkey Point EPU Power Ascension and Test Plan,” and Table 2.12-4, “Transient Tests,” which described transient testing to be performed as part of the licensee’s PATP for EPU. The licensee stated in the LAR that integrated plant analyses were performed to define the performance criteria of various plant modifications necessary to accommodate the EPU, and that the results were used, in part, in lieu of large transient testing to verify that the plant systems are capable of safe operation in the uprated condition. Table 2.12-4 specifically lists the large transient tests performed in the original startup test program and justification for those tests not planned to be performed as part of the licensee’s PATP for EPU.

For PTN, these tests, originally performed during initial plant startup, are the 10 percent load swing test (originally performed at 30 and 80 percent OLTP); 20 and 50 percent load reduction test; and the generator trip test, which generally follow the tests described in Table 2 of SRP 14.2.1. The justification for not performing such tests was presented in Attachment 4 to the LAR which provides a discussion of the PATP covering power ascension up to the full EPU power level of 2644 megawatt thermal (MWt) to verify acceptable performance. However, the licensee stated that several smaller transient tests will be performed as part of the EPU PATP due to the number of modifications made to the balance-of-plant (BOP) systems to accommodate EPU power levels. A discussion of these tests and the licensee’s justification for a test program that does not include all of the power-ascension testing that would normally be performed, is further

discussed below in, “SRP 14.2.1, Section III.C, Use of Evaluation To Justify Elimination of Power-Ascension Tests,” of this safety evaluation.

The licensee 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, the licensee stated that PTN has years of operating experience at the current licensed power level such that system interactions are well known and has also benefited from industry operating experience in power uprate implementation from several industry sources, including the Institute of Nuclear Power Operations. Two other previously uprated PWRs (R.E. Ginna Nuclear Power Plant (Ginna) and Beaver Valley, Units 1 and 2) have uprated to core thermal power levels that are similar to that requested by PTN (2644 MWt and 2900 MWt, respectively) and have operated successfully at the new power levels since NRC approval in July 2006. Ginna is a Westinghouse two-loop designed plant and Beaver Valley and PTN Units are three-loop Westinghouse nuclear steam supply system plants.

As stated in the LAR, the PTN PATP is primarily an initial power ascension test plan in which power will be increased in a slow and deliberate manner, stopping at predetermined power levels for steady-state data gathering and formal parameter evaluation. The program consists of a combination of normal startup and surveillance testing, a mixture of power ascension monitoring, post-modification testing of components and systems, analytical evaluation, and transient testing response, to verify that the plant can operate safely at the uprated core thermal power. At approximately 87 percent EPU power (2300 MWt), power will be increased through 5 additional test conditions, each differing by approximately 3 percent of the EPU-rated thermal power. Both dynamic performance during the ascension and steady-state performance for each test condition will be monitored, documented and evaluated against predetermined acceptance criteria. In addition, several transients will also be performed to provide additional confidence in the validity of the analytical models and assumptions used in the analysis of plant modifications and integrated plant response to transients. Transient data will be compared against predictions provided by the same analytical models used in design verification for EPU. Any significant differences between predictions and test data will be evaluated and reconciled before proceeding with the power ascension.

Conclusion

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 4 to the LAR, and the applicable sections of the PTN FSAR, that 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.

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 loss of all offsite power, tripping of the main turbine generator set, and loss of power to all reactor coolant pumps. 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 AOOs described in the plant-specific design basis; and (3) involves the integrated response of multiple SSCs.

The staff reviewed Attachment 4 to the LAR which discussed planned modifications scheduled to be performed. Modifications necessary to allow operation at EPU conditions are scheduled to be implemented over two phases. The first phase is planned during the fall 2010 outage for Unit 3 and the spring 2011 outage for Unit 4 and will be made in accordance with 10 CFR 50.59. In the second phase, subject to NRC approval of the LAR, the remaining modifications required to support EPU will be implemented before or during the spring 2012 outage for Unit 3 and the fall 2012 outage for Unit 4. A list of key planned modifications associated with the proposed EPU is provided in Attachment 4, Table 1.0-1, “PTN Unit 3 and Unit 4 Power Uprate Key Planned Modifications.” Some of the key modifications planned prior to operation at EPU conditions include, but are not limited to upgrading main steam isolation valves (MSIVs), Main feedwater system pump upgrades, condensate pump replacement, modification of feedwater isolation valves, feedwater heater replacement, modify and refurbish auxiliary feedwater pumps, and modify feedwater control valves. Functional and operational post-modification testing will be performed for each modification to verify satisfactory installation and performance.

The staff also reviewed the licensee’s approach relative to assessing the aggregate impact of the proposed equipment modifications. In Section 2.12.1.2.6.1, “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 four categories of plant conditions: normal operation, 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 based on analyses results performed, the plant responses to Condition I, II, III, and IV initiating events satisfied the acceptance criteria.

Analyses and evaluations performed by the licensee used the NRC-approved LOFTRAN computer code, which has been used for many years by Westinghouse for accident analysis evaluations for many Westinghouse-designed nuclear power plants. Westinghouse report WCAP-7907-P-A, “LOFTRAN Code Description,” April 1984, describes the LOFTRAN verification process performed by Westinghouse for transients including reactor trip from 100 percent power, 100 percent load reduction, and step load changes. As discussed by the

licensee in the LAR, the plant responses to Condition I, II, III, and IV initiating events at EPU conditions are consistent with the characteristic responses based on operational and analytical experience at PTN at the current power conditions, as well as similar experience at other Westinghouse NSSS-designed 3-loop nuclear power plants currently operating at or above 2644 MWt.

Conclusion

The 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.

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 thermal-hydraulic 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 emergency operating procedures (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 14.2.1, 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, operating and EOPs, 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.

PTN's EPU PATP is comprised of power ascension monitoring, post-modification testing, analytical evaluation and some transient testing to ensure that the plant can operate safely at its new uprated core thermal power. The PATP does not include all the power ascension testing that would typically be performed during initial startup of a new plant. The PTN test plan is based on industry operating experience pertaining to power uprate and has used this experience 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 original startup tests against the review criteria established in SRP 14.2.1. These tests include a 10 percent load swing test performed at 30 and 80 percent OLTP; a 20 percent load reduction test performed at 70 to 50 percent OLTP; a 50 percent load reduction test performed at 100 to 50 percent OLTP; and a generator trip test originally performed at approximately 110 MWe. These large load transient tests are listed and discussed in Table 2.12-4 of Attachment 4 to the LAR. The licensee presented its justification for not reperforming these tests in Section 2.12.1.2.6.2, "Justification for Exception to Transient Testing," of Attachment 4 to the LAR.

The licensee's basis for not performing these tests as part of the proposed EPU PATP primarily relies on an analytical justification using the NRC approved computer code LOFTRAN to evaluate plant responses to Condition I and II initiating events at EPU conditions. Additional justification provided by the licensee in the LAR 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; recommendations from NSSS and BOP vendors; PTN plant-specific operating experience at greater than OLTP power levels; and industry experience at other uprated PWRs. The licensee stated that the results of these tests and analyses, coupled with 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 2.12-3 of Attachment 4 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 PTN's EPU PATP due to recommendations from the NSSS vendor and a review of PTN's original PATP; and that performing such transient 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. The following large transient tests, presented in Section 2.12.1.2.6.2 of Attachment 4 to the LAR, were performed during PTN's initial PATP for both Units 3 and 4: a 10 percent step load test at 30 and 80 percent power; a 50 percent load reduction from 70 and 100 percent power; load cycle tests at 40 and 80 percent power; and a natural circulation test (7 percent nuclear heat and partial cooldown). However, the licensee stated in the LAR that due to a number of modifications made to the BOP systems to accommodate EPU power levels, PTN will perform several smaller transient tests as part of the EPU PATP.

The purpose of these tests are to provide additional confidence in the validity of the analytical models and assumptions used in the analysis of plant modifications and integrated plant response to transients, and also verify that no new thermal hydraulic phenomena or adverse system interactions are created by the proposed EPU. The tests, listed in Table 2.12-2 of Attachment 4 to the LAR include the following: turbine overspeed trip from 5 percent EPU power; 10 percent ramp load change at new 30 percent and 100 percent EPU power; turbine stop, governor and intercept valve testing at 35 percent EPU power; and steam generator level/feedwater flow dynamic testing at 30 percent, 87 percent and 95 percent EPU power.

Industry (PWR) Transient Operating Experience at Uprated Power Levels

With respect to the review criteria established in SRP 14.2.1, 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 PTN. Section 2.12.1.2.2 of Attachment 4 to the LAR states, in part, that "In addition to Beaver Valley, Units 1 and 2, and the R.E. Ginna Nuclear Power Plant, PTN has benefited from industry operating experience in power uprate implementation from several industry sources, including the Institute of Nuclear Power Operations (INPO)." However, in Section 2.12.1.2.6.2, "Justification for Exception to Transient Testing," of Attachment 4, a discussion of such industry operating experience was not presented. Such information 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. In response to a request for additional information from the staff, the licensee provided information in a letter dated April 28, 2011, relative to post-EPU startup testing at both Ginna (Westinghouse 2-loop design) and Beaver Valley (Westinghouse 3-loop design). The licensee stated that the Ginna transient experience in conjunction with the PTN specific operating experience, and the results of predictions of plant response at EPU conditions support the request not to perform certain transient tests, including tests of the steam dump control system, plant trips, load swings, and load reductions. With respect to Beaver Valley, the licensee concluded that the results of the testing performed demonstrated that the plant response remained within the preestablished acceptance criteria at EPU and that the results are a strong indicator of those expected at PTN for the increase to EPU.

The staff also reviewed licensee event reports (LERs) for at least four events that have occurred at Beaver Valley since 2002 involving reactor trips from 100 percent CLTP. At this power level, it is equivalent to 101.5 percent OLTP since the NRC approved a 1.4 percent measurement uncertainty power uprate for both units in September 2001, and an 8 percent EPU in July 2006. All four LERs reviewed by the staff concluded that the plant responded as expected and all required safety related systems functioned as required. For the R.E. Ginna Nuclear Power Plant, the staff identified in its review of LERs three plant trips which occurred at 100 percent EPU power (approximately 117 percent OLTP). The licensee implemented the EPU during the Fall of 2006, shortly after the NRC approval of Ginna's 16.8 percent EPU in July 2006. The three LERs (January 27, 2007; March 16, 2007; and December 30, 2009) reported plant trips due to a loss of electrical generation, MSIV closure and a loss of electro-hydraulic control system pressure and concluded, as a result of the event, that the plant responded as expected and all safety systems operated as designed. The staff also reviewed Ginna's Startup Test Report, dated January 31, 2007, which documented the results of its PATP to achieve EPU conditions. The report stated that Ginna's PATP was a comprehensive plan that incorporated the design predictions from the EPU analyses, operating experience from other EPUs, post-modification testing for the plant modifications installed, and plant surveillance testing required by technical specifications. The report described the power ascension testing results following uprate at EPU conditions and discussed several transient tests which were performed as part of the EPU. Power was uprated to 1775 MWt and low and full power transient tests were performed including a manual turbine trip at an initial power level of 30 percent; a 10 percent load change test at 30 percent and 100 percent EPU power; a turbine overspeed trip from 20 percent EPU power; a turbine stop valve, governor valve and intercept valve test at 50 percent EPU power; and a steam generator level/feedwater flow dynamic test at 30 percent and 100 percent EPU power.

Except for the manual turbine trip test, the transient testing scheduled to be performed by PTN, as described in Table 2.12-2 of the PTN PATP, is nearly the same as performed by Ginna. The main difference is in the EPU power levels in which certain transient tests will be performed (slightly lower EPU power levels for the PTN testing). Plateau testing from 85 percent to 100 percent power was also performed in 3 percent increments over a 10 day period to obtain plant data at each power ascension plateau. The report stated that for the low power transient testing performed (steam generator level test; 10 percent power ramp test; 30 percent manual trip test; main turbine overspeed test; and turbine valve testing at 47 percent power), all parameters responded as expected according to the predicted design program and all acceptance criteria were met. For the full power transient tests performed (10 percent power ramp test from 100 to 90 percent reactor power; steam generator level control test at 90 percent power; and 10 percent power ramp test from 89 to 99 percent reactor power), the report concluded that all parameters responded as expected according to the predicted design program, and that the satisfactory completion of the turbine trip test fulfilled the purpose of the pressurizer level control test, pressurizer pressure control test, and steam dump test performed during original plant startup testing.

PTN Plant-Specific Transient Experience at Uprated Power Levels

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 transients experienced at PTN. The licensee provided additional information in a letter dated

April 28, 2011, in response to a request for additional information from the staff relative to additional examples of plant specific operating experience. The licensee provided several examples of recent reactor trips in 2010 which demonstrated satisfactory performance. The staff reviewed LERs for both Units 3 and 4 relative to operating events, primarily planned and unplanned reactor trips, and plant transient performance. As noted by the staff's review, at least 10 events have occurred at PTN since 2000 involving reactor trips from various power levels; most of which between 95 to 100 percent CLTP. This translates to approximately 104.5 percent OLTP since the NRC approved a 4.5 percent stretch power uprate for both Units 3 and 4 in September 1996. Three of the events occurred in 2010 while operating at 100 percent CLTP (104.5 percent OLTP). For all three LERs reviewed by the staff, the report stated that the plant responded as expected to the reactor trip and all systems functioned as designed, thus no impact on safety.

Use of LOFTRAN to Justify Exception to Large Transient Testing

In the EPU licensing report, the licensee stated that analyses and evaluations have been performed for the Condition I operating transients to assess the aggregate impact of the equipment modifications and setpoint changes for EPU conditions. These analyses and evaluations used the NRC-approved LOFTRAN code.[163]

The original NRC safety evaluation report approving LOFTRAN concluded that the code had been verified for transients including a reactor trip from 100 percent power, a 100 percent load reduction, and step load changes. The verification included comparison of LOFTRAN results to actual plant data and code-to-code comparisons. The verification also included an analysis of a steam generator tube rupture event at the R. E. Ginna Power Plant.

To add to the original verification basis, the licensee stated that LOFTRAN-predicted responses to plant transients are consistent with characteristic responses and analytic experience at PTN and experience on several similar Westinghouse-designed 3-loop nuclear power plants that also use the LOFTRAN computer code to analyze Condition I events and operate at exactly the same power level.

The licensee concluded that, because LOFTRAN has been used for analysis in a wide variety of different Westinghouse designed nuclear power plants including other similar Westinghouse designed 3-loop nuclear power plants, the computer code can be used to predict the plant response to a wide variety of transients, and thus negates the need to perform plant transient testing to validate predicted code responses to large plant transients.

The licensee also stated that process parameter changes being made to accommodate the power increase are within the design capability of the related systems, or that necessary upgrades are being installed, such that no new thermal-hydraulic phenomena are being introduced by either the physical modifications or changes in operating conditions.

The license updated its LOFTRAN analysis inputs and models to incorporate EPU equipment modifications and setpoint changes as well as EPU operating conditions. The licensee stated

[163] Westinghouse Electric Company, "LOFTRAN Code Description," WCAP-7907-P-A, April, 1984. ML080650325.

that modified control systems modeled in LOFTRAN included the reactor control system, the reactor coolant temperature control system, the pressurizer level control system, the pressurizer pressure control system, the steam generator level control system, and the steam dump control system.

The licensee modeled the following events using the LOFTRAN computer code:

- Step load changes:
    - 10 percent increase from 90 percent to 100 percent power
    - 10 percent decrease from 100 percent to 90 percent power
- Turbine trip from 100 percent power
- 50 percent load rejection from 100 percent power.

Based on the results of these analyses, the licensee concluded that a ramp load increase and decrease of 5 percent power per minute between 15 to 100 percent power would be acceptable at EPU conditions.

Based on the updated analytic results, the licensee concluded that:

- Plant responses to Condition I events satisfied acceptance criteria
- The NSSS control system responses were stable
- Plant responses to Condition I initiating events have acceptable margins to reactor trip and engineered safety features actuation
- No new system dependencies or interactions are being introduced by the changes

NRC Technical Evaluation

To evaluate the acceptability of the licensee's LOFTRAN modeling insofar as it supports the requested exception from large-transient testing requirements, the NRC staff reviewed the information submitted by the licensee, and considered previous NRC-accepted applications of the LOFTRAN code. The NRC staff also assessed WCAP-7907-P-A, the NRC-approved topical report describing the LOFTRAN code, and information supporting the NRC staff review of WCAP-7907. Based on the information considered by the NRC staff, the staff concluded that LOFTRAN provides an acceptable prediction of plant transients and justifies exception from large transient testing.

The licensee used the LOFTRAN code to analyze Condition I events. Condition I events are transients such as small load swings or power maneuvers that proceed with margin to reactor trip or engineered safety features actuation.

The LOFTRAN code was approved by the NRC staff. Among the transients listed for the initial LOFTRAN approval were loss of external load, the thermal-hydraulic conditions for which are normally bounding of a turbine trip or more minor load swing.

The licensee also stated that LOFTRAN has been used successfully to model uprated plant transients in other instances. The licensee referred to similar plant transients to those referenced here in support of uprate applications for both Ginna and Beaver Valley nuclear power stations.

The staff is also aware of additional instances where LOFTRAN modeling has been performed to predict plant performance at uprated conditions.[164] An example event was the loss of main feedwater pump while operating at full power, which led to a reactor trip, at the Kewaunee nuclear station. The code predicted that pressurizer and steam generator safety valves would not open if the steam dump control and pressurizer pressure/level controls worked properly. During the real event, none of these valves opened. The code also predicted that there would be no safety injection if reactor control and pressurizer pressure control systems worked properly. During the real event, there was no safety injection actuation. This transient comparison demonstrated the capability of LOFTRAN to predict system responses and reactor performance at uprated condition.

In addition to the uprate verification based on the Kewaunee loss of feedwater event, the original LOFTRAN verification included various reactor trip events and several step load changes. The verification data showed that, in most cases, the LOFTRAN code over-predicted system perturbations, meaning that the computer code would generally predict less available margin to trip system and instrument actuation setpoints than plant performance would demonstrate.[165] In all cases, however, the general agreement between LOFTRAN-predicted data and actual plant response was good.

Based on the above considerations, the NRC staff concluded that LOFTRAN has the capability, which has been acceptably demonstrated, to provide a realistic prediction of Westinghouse PWR performance at uprated, operating transient conditions.

In summary, the NRC staff considered whether LOFTRAN provides an acceptable prediction of the response to uprated, operational transients at PTN. The NRC staff reviewed original LOFTRAN validation data, which was based on comparisons to transients at other Westinghouse plants, and concluded that LOFTRAN can provide an acceptable prediction of plant response to operational transients. The licensee also provided information to demonstrate that the LOFTRAN code has been used in a similar manner in the past. Based on the NRC staff's review as described above, the NRC staff finds that the licensee's use of LOFTRAN to predict PTN performance during uprated operational transients is acceptable, insofar as such use justifies the licensee's request for exception from large transient testing.

Conclusion

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, PTN addressed several factors discussed in SRP 14.2.1, Section III.C.2. These factors included industry operating experience at recently uprated PWRs, plant response to actual reactor trips for other similar PWRs, experience gained from actual PTN plant-specific events, and satisfactory results of the EPU startup testing program for the R.E. Ginna Nuclear

[164] Korsnick, Maria, Contrallation Energy, "Response to Requests for Additional Information Regarding Topics Discussed on Conference Calls," Docket 50-244, February 16, 2006. ML060540349.
[165] Rahe, Jr., E. P., Westinghouse Electric Corporation, letter to Miller, J. R., USNRC, "Transmittal of Slides from the December 15, 1981, Westinghouse Meeting on the LOFTRAN and MARVEL Codes," January 19, 1982, Legacy Accession 8201270359 (non-proprietary) and 8201270375 (proprietary).

Power Plant. Additionally, the licensee referenced the use of the NRC-approved WCAP-7907-P-A which describes the LOFTRAN verification process performed by Westinghouse for transients including reactor trip from 100 percent power, 100 percent load reduction, and step load changes. This code has been used for many years for accident evaluations for Safety Analysis Reports and for control system performance.

Based on the review, the staff concludes that PTN's 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 quality assurance 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.

Balance-of-plant (BOP) systems considerations

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 design-basis accidents, 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 Standard Review Plan (SRP) (NUREG-0800), 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 anticipated operational occurrence 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 PTN EPU licensing report against the considerations discussed in SRP 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 condensate pumps, replacement of the high-pressure feedwater heaters, modification of the main feedwater pumps, modification of the feedwater control valves, modification of the feedwater isolation valves, and replacement of the main high-pressure turbine.

The staff reviewed proposed testing of the steam dump system at PTN. Because the licensee is proposing neither to modify nor to credit additional capacity for the atmospheric steam dump and turbine bypass valves, the staff agreed with the licensee's assessment that integrated plant transient testing for the purpose of demonstrating the capacities of the steam dump and turbine bypass valves is not necessary.

The staff reviewed the scope of integrated plant testing proposed for evaluation of physical modifications associated with the power uprate. System and component level testing would

generally provide adequate assurance that the modified components would perform acceptably in service. Adequate operation of the replacement main high 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 of the condensate and feedwater system modifications would provide the greatest assurance the system will perform its important to safety function of heat removal from the reactor coolant system during normal operation, including mild transient conditions.

Table 2.12-2, “Large Plant Transient Tests in Turkey Point EPU Power Ascension Test Plan,” of the EPU licensing report addressed proposed testing involving integrated plant response, including the response of the condensate and feedwater system to plant transients. This table included descriptions of proposed 10 percent ramp load change tests (from 30 and 100 percent EPU power) and steam generator level/feedwater flow dynamic testing from 30, 87, and 95 percent EPU power. The licensee described that these tests would provide an indication that no unanticipated interactions had been introduced and the feedwater control system would operate properly at EPU conditions.

Section 2.12.1.2.6.1, “Transient Analytical Methodology,” of the EPU licensing report described how the licensee used the LOFTRAN computer code to evaluate the plant transient response. With respect to BOP system performance, the transients evaluated for normal operation, including anticipated operational occurrences, are most relevant because the BOP systems would be expected to operate throughout many of these transients. The specific transient events evaluated included a 10 percent step load increase, a 10 percent step load decrease, and a 50 percent load reduction. This code did not model the BOP systems explicitly; rather, the code included assumptions related to BOP system performance.

Section 2.12.1.2.3.2 of the PTN EPU licensing report stated that the licensee would compare transient test data for tests listed in Table 2.12-2, “Large Plant Transient Tests in Turkey Point EPU Power Ascension Test Plan,” against predictions provided by analytical models used in design verification for EPU. The staff requested that the licensee describe the scope of the analytical modeling and the criteria that would be employed to evaluate reconciliation of test results with model predictions prior to proceeding with power ascension. In the Attachment to the letter dated April 14, 2011,[166] the licensee described that a more detailed model had been developed for Turkey Point. The licensee used this more detailed model to analyze a bounding 50 percent load reduction transient at EPU conditions to determine the steam generator level/feedwater dynamic responses to the transient. The model included the detailed response of the steam generators and feedwater system to accurately predict the shrink/swell of the steam generator water level in transient conditions. The licensee stated that the model has been demonstrated to compare well against plant data and has been used for other similar EPU programs, such as for Beaver Valley Units 1 and 2.

The licensee described that the feedwater control system would be monitored during the EPU power ascension to ensure the feedwater controls are operating correctly and that steam generator level is automatically controlled within operating limits. This monitoring in

[166] ML11105A146

combination with completed analyses and operating experience would provide reasonable assurance that the feedwater 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 condensate and feedwater systems to be of limited scope. Operating experience indicated that similar limited scope modifications have been successfully implemented at other units, including three-loop Westinghouse reactors comparable to PTN. 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 feedwater 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.

Conclusion

The licensee has evaluated the impact of the proposed EPU on BOP systems and components, demonstrating that adequate power ascension testing would be completed to support safe operation at the proposed EPU Power level. Based on the provisions of the licensee's power-ascension test program, the NRC staff finds that the licensee has accounted for the effects of the proposed power uprate on the BOP systems. The licensee has adequately justified the limited scope of proposed transient testing of BOP components based on computer modeling of plant transients and the operating experience of similar plants that have implemented similar power uprates. Therefore, the NRC staff finds the proposed EPU power ascension test plan acceptable.

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 quality assurance program requirements. The following should be identified in the EPU test program:

- The method in which initial approach to the uprated EPU power level is performed in an incremental manner including steady-state power hold points to evaluate plant performance above the original full-power level,

- Appropriate testing and acceptance criteria to ensure that the plant responds within design predictions including development of predicted responses using real or expected values of items such as 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 Conditions) for steady-state data gathering and formal parameter evaluation, consistent with the PATP. A summary of the PTN PATP is provided in Table 2.12-1 of the LAR. The typical post-refueling power plateaus will be used until the current full power condition is attained at approximately 87 percent of the EPU power level (2300 MWt), with additional equipment and plant transient testing performed at 25 and 50 percent of the EPU power level to verify expected component, system and integrated plant performance. Prior to exceeding the current licensed core thermal power of 2300 MWt, the steady-state data gathered at the predetermined power plateaus and transient data gathered during the specified transient tests at low power, as well as observations of the slow, but dynamic power increases between the power plateaus, will allow verification of the performance and dynamic response of the EPU modifications.

In particular, 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 87 percent of EPU power, power will be increased through five additional Test Conditions, each differing by approximately 3 percent of the EPU-rated thermal power. Both dynamic performance during the ascension and steady-state performance for each Test Condition will be monitored, documented and evaluated against pre-determined acceptance criteria. In addition to the steady-state parameter data gathered and evaluated at each test condition, several transient tests will also be performed, as listed and described in Table 2.12-2 of Attachment 4 to the LAR. PTN anticipates that such tests will adequately identify any unanticipated adverse system interactions and allow them to be corrected in a timely fashion prior to full power operation at EPU conditions.

Conclusion

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.

2.13 Risk Evaluation

2.13.1 Risk Evaluation of Extended Power Uprate

Regulatory Evaluation

Florida Power and Light Company (FPL, 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. In accordance with the Nuclear Regulatory Commission (NRC) review standard, RS-001, "Review Standard for Extended Power Uprates," (December 2003), Section 13, a risk evaluation is conducted to determine if "special circumstances" are created by the proposed extended power uprate (EPU). As described in Appendix D of NRC's NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants" (Standard Review Plan or 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 (approximately 15 percent greater than the currently licensed power level) in terms of changes in core damage frequency (CDF) and large early release frequency (LERF) from internal events, external events, and shutdown operations. In addition, the 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 individual plant examination (IPE), individual plant examinations of external events (IPEEE), or by industry peer reviews. The staff used the guidance provided in Regulatory Guide (RG) 1.174, Revision 1, "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.

NRC Technical Evaluation

The staff reviewed the risk evaluation submitted for Turkey Point Nuclear Power Plant (PTN) Units 3 and 4 by FPL, as supplemented by responses to the staff's request for additional information. 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 PTN IPE, which is based on a full scope level 2 PRA performed in fulfillment of Generic Letter (GL) 88-20. The NRC issued a safety evaluation report (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 PTN 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 their 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 December 2002, Westinghouse Owners Group (WOG) performed a peer review of the PTN PRA. The review identified 2 "A" level (A-Level) Facts and Observations (F&Os) and 27 "B" level (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.

The staff finds that all F&O findings were properly assessed and dispositioned in regard to this application.

Conclusions Regarding the Quality of the PTN 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 PTN IPE and IPEEE; and reviewed the WOG peer review open F&Os and their dispositions for this application.

Based on its evaluation, the NRC staff finds that the PTN 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 PTN PRA to determine the CDF and LERF of the post-EPU plant.

Initiating Event Frequencies

The PTN PRA model includes initiating event categories, which includes transient initiating events, loss of offsite power, loss-of-coolant accident initiators, steam generator tube rupture initiators, anticipated transient without scram 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, pressure operated relief valve challenges, and increased flow accelerated corrosion.

Loss of Offsite Power (LOOP) – The licensee states in their 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 safety injection actuation signal nonsafety 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.

Loss-of-Coolant Accident (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 power-operated relief valve (PORV) challenge frequency by 50 percent resulted in a CDF increase of 2.7E-9 per year for both plants.

Steam Generator Tube Rupture (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.

Anticipated Transients Without Scram (ATWS) – The significance of the ATWS event is evaluated in terms of unfavorable exposure times (UETs), which reflect the fraction of cycle the plant would have to wait before the moderator temperature coefficient is sufficiently negative such that ATWS events could be mitigated with charging pumps and other resources.

As no changes are planned for the reactor protection system or the ATWS Mitigation System Actuation Circuitry, no change is anticipated in the likelihood of rod cluster control assembly insertion failure. Furthermore, the EPU core design will result in the plant continuing to be categorized as having a low reactivity core; therefore changes to the UET are not expected. Consequently, no change in ATWS frequency is expected for the EPU.

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 that the licensee adequately addressed internal initiating event frequencies based on the licensee properly implementing the equipment modifications and replacements 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 PTN internal events PRA and are acceptable.

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. The staff concludes that there are no issues with component reliabilities/failure

rates modeled in the PTN internal events PRA and the expectation is that there will be no change in component reliability as a result of the EPU and, therefore, acceptable.

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.

No changes are expected in reactivity control methods or effectiveness due to EPU. The results of generic bounding assessments performed for ATWS will remain valid since fuel design following EPU will retain its designation as a low reactivity core and changes to UET are not expected. PRA assessments indicate that as a result of an EPU plant modification to add an additional valve to the main feedwater (MFW) bypass line, the probability of recovery of MFW following a loss of main feedwater (LMFW) event is marginally decreased, resulting in EPU ATWS CDF increase of about 4E-9 per year and LERF increase of 2E-10 per year.

There are no significant changes in the manner of operation, pressure, or components due to EPU that affect pressure control success criteria. EPU changes to the plant safety valve setpoints are minimal and will not impact plant risk.

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 feedwater 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. Additional impacts to operator response times are listed below:

1. Maintain the SG level at 50 percent of the narrow range (NR) indication instead of 60 percent.
2. Increase the SG low level reactor trip set point from 10 percent NR to 16 percent NR.
3. Modify procedures to allow entry into feed-and-bleed at SG wide range level at 33 percent instead of 22 percent.

The Modular Accident Analysis Program (MAAP) analyses show that implementation of the EPU will decrease the time to successfully implement OTC from 145 minutes under current conditions to 95 minutes at EPU conditions. The risk implication of this time decrease on operator actions is considered in the human reliability assessment.

No changes to small-small LOCA success criteria are anticipated, however; the greater EPU power levels results in an increased demand for safety injection following small and medium LOCAs. While equipment requirements are generally the same, EPU high head safety injection requires two cold leg injection lines to deliver adequate injection flow, while current conditions require availability of only a single injection line. The MAAP was utilized to establish small-small and small LOCA success criteria; whereas, medium and large LOCA success criteria are based on design basis inputs.

The EPU associated conditions reduce the time to reach boron solubility limits in the core for medium and large LOCAs from 12 hours to 6.7 hours. This condition can result in boron precipitation on the fuel assemblies, which reduces heat transfer rates, and may lead to core damage. To preclude this occurrence, the licensee will revise the associated emergency operating procedures (EOPs) to direct the operators to reestablish hot leg/cold leg injection no later than 5.5 hours following the initiation of safety injection in the cold leg. The only potential impact on risk is from an increase in the probability of the operators failing to reinitiate safety injection within this time period. The staff notes that due to the significant amount of time available for this operator action for EPU conditions, the impact on human error probabilities (HEP) and plant risk is negligible.

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 PTN 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 PTN 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 following methodologies 1) Human Cognitive Correlation/Operator Reliability, and 2) Cause Based Decision Tree Methodology 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.

The EPU has no impact on estimated operator recovery actions for approximately one half of the operator actions included in the PRA. To offset the impact of EPU to human operator timings, two changes were made to the EOPs: 1) the setpoint for implementation of feed and bleed cooling was changed from 22 percent wide range to 33 percent wide range and 2) the step to shut off residual heat removal (RHR) pumps in the event of a LOCA where pressure remains high was moved to an earlier point in the EOP.

An assessment of the net risk impact of the current plant and EPU HRA were performed. This analysis consisted of estimating the plant risks as monitored by CDF and LERF. Results of these analyses indicate that the impact of EPU on HEPs is limited to about 4.6E-8 CDF and 4.1E-9 LERF for Unit 3 and 5.3E-8 CDF and 4.3E-9 LERF for Unit 4.

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 PTN internal events PRA and are acceptable.

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 Level 2 evaluation builds off the CDF accident sequences and bins results into large early release, 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	Increase	Percent Change
Unit 3 CDF	4.4E-7/year	4.8E-7/year	4.6E-8	11
Unit 3 LERF	1.3E-8/year	1.7E-8/year	4.1E-9	30
Unit 4 CDF	4.4E-7/year	4.9E-7/year	5.3E-8	12
Unit 4 LERF	1.3E-8/year	1.8E-8/year	4.3E-9	32

The increases in internal events CDF and LERF, shown in Table 1, falls within the RG 1.174 acceptance guidelines for being “very small”, and therefore do 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.

External Events Risk Evaluation

The licensee does not have fire or seismic PRA models. The IPEEE studies used the Electric Power Research Institute (EPRI) fire-induced vulnerability evaluation methodology to address external risk from fire sources. For the seismic IPEEE process, the licensee used a site-specific seismic program associated with USI [Unresolved Safety Issue] 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, PTN implemented the EPRI fire-induced vulnerability evaluation methodology. The IPEEE staff evaluation notes that 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 nonscreened 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 4E-6 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.

Fire frequencies and fire mitigation 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 nonrisk-informed application.

Seismic Risk

In the seismic IPEEE, the site-specific program for seismic adequacy evaluations for PTN 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. PTN'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 PTN for performing a scaled-back analysis include: (a) very low probability of having an earthquake at the SSE (safe shutdown earthquake) level; and (b) very low values of potential offsite releases and potential risk reductions given the postulated accident scenarios and seismic hazards. PTN'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 system 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 nonsafety) 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 design basis earthquake (0.1g). This evaluation indicated that both current and EPU CDF estimates were very close to 1E-8 per year. Similarly, LERF estimates were on the order of 1E-10 per year.

The staff finds that the licensee's characterization of the seismic risk at PTN is not complete and that the steps undertaken during the seismic IPEEE process leads to an inconclusive risk estimate. In the IPEEE safety evaluation, the NRC staff notes that there are several weaknesses in the licensee's seismic submittal; however, the staff indicates that the impact of these weaknesses appeared to be minimal because the seismic risk at PTN was perceived to be low. Based on a simplified approach to estimate the core damage frequency from a seismic margins approach and using the latest published United States Geological Survey seismic hazards information, the staff estimates the PTN seismic CDF is about or below 1E-5 per year. Since all structural plant modifications and anchoring of all replacement components (safety and nonsafety) 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 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 PTN 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 PTN 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 and, therefore, is acceptable. 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 safety evaluation demonstrates that the shorter available time window under EPU would not adversely impact safety consequences. 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 and is acceptable. 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 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 RENEWED FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION CHANGES

The licensee proposed changes to Renewed Facility Operating License DPR-31 and DPR-41 and its Appendix A, Technical Specifications (TS), in order to implement the extended power uprate (EPU). The technical bases for these changes have been evaluated in detail and set forth in the sections above. Therefore, Sections 3.1 and 3.2 below only describe the proposed renewed facility operating license and TS changes.

3.1 Renewed Facility Operating License DPR-31 and DPR-41

- License Condition 3.A

The licensee proposed to change the maximum power level from 2,300 megawatt thermal (MWt) to 2,644 MWt.

This change reflects the proposed 15 percent increase in the thermal power level for the plant including a 13 percent power uprate and a 1.7 percent measurement uncertainty recapture, and is consistent with the licensee's supporting safety analyses. The various technical aspects of this proposed change had been evaluated and found acceptable in the above sections of this SE; therefore, the NRC staff finds this proposed change acceptable. The license condition, as proposed, will read as follows:

3. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the

Commission now or hereafter in effect; and is subject to the additional conditions specified below:

A. Maximum Power Level

The applicant is authorized to operate the facility at reactor core power levels not in excess of 2644 megawatts (thermal).

3.2 Technical Specifications

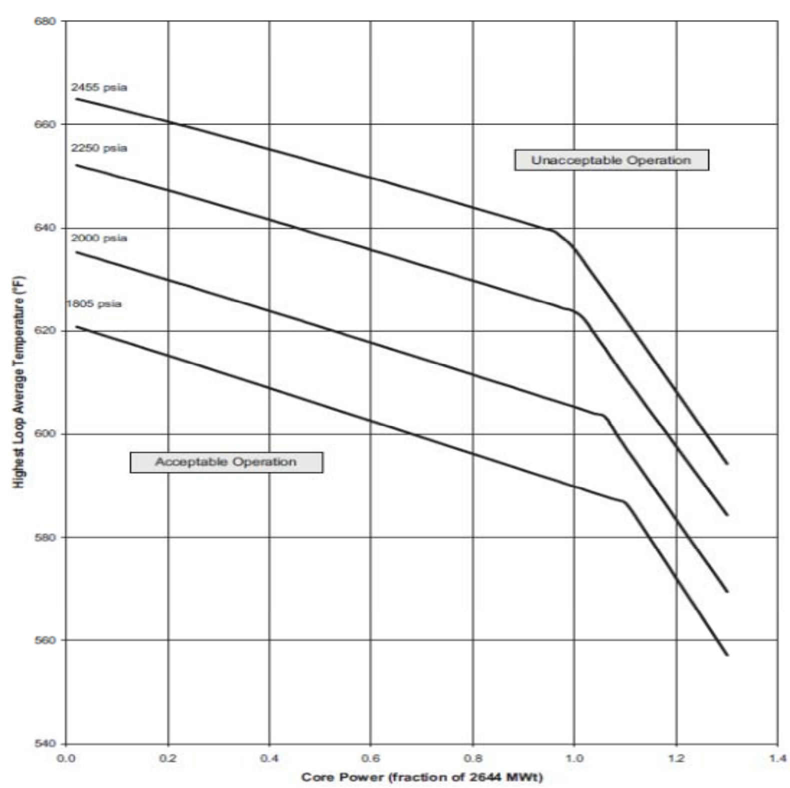
Technical Specification, 2.1 Safety Limits, Reactor Core

Current TS

Figure 2.1-1 Reactor Core Safety Limit – Three Loops in Operation (T_{avg} (°F) vs Power (fraction of nominal)) (figure omitted)

Proposed TS (NOTE: With the issuance of Amendment Nos. 247 and 243, Figure 2.1-1 has been relocated to the COLR. See explanation below.)

Figure 2.1-1 Reactor Core Safety Limit – Three Loops in Operation (Highest Loop Average Temperature (°F) vs Core Power (fraction of 2644 MWt) is as shown below



The licensee stated:

> Departure from Nucleate Boiling (DNB) analyses were required to define new core limits, axial offset limits, and Condition II accident acceptability to support operation at EPU conditions.

Nuclear Regulatory Commission (NRC) Technical Evaluation

Title 10 of the *Code of Federal Regulations* (10 CFR) 50.36 requires the establishment of safety limits in the facility technical specifications (TS). Safety limits are important process variables that are found to be necessary to reasonably protect the integrity of certain of the physical barriers that guard against the uncontrolled release of radioactivity. The departure from nucleate boiling ratio (DNBR) safety limit is that which correlates the local fuel thermal-hydraulic behavior to fuel cladding integrity. The DNBR safety limit is based on numerous parameters, including principally the fuel cladding surface heat flux, the reactor coolant system pressure, the reactor coolant temperature, and the fuel bundle geometry, since the bundle geometry affects flow mixing in the core and therefore fuel cooling performance.

The figure above correlates core power and the highest permissible coolant loop temperature at several operating pressures. The figure provides the basis for initial conditions assumed in the DNBR transient analyses.

As the figure provides the basis for initial conditions assumed in the DNBR transient analyses, the staff finds the proposed revision acceptable in accordance with the findings in Sections 2.8.3, “Thermal and Hydraulic Design,” and 2.8.5, “Accident and Transient Analysis,” of this safety evaluation (SE).

By letter dated February 21, 2011,[167] FPL submitted a license amendment request (LAR) to revise the Turkey Point, Units 3 and 4 technical specifications (TSs) to relocate selected figures and values from the TSs to the Core Operating Limits Report (COLR). By letter dated February 24, 2012,[168] the NRC staff approved the license amendment and issued Amendment Nos. 247 and 243 for Turkey Point, Units 3 and 4, respectively.

By Letter dated March 15, 2012,[169] FPL identified those COLR TS pages issued in Amendment Nos. 247 and 243 that supersede the EPU application TS pages. In addition, the licensee also stated that the EPU parameters included on these pages will be relocated to the COLR and that the values of the relocated parameters remain unchanged from the values reviewed by the NRC staff for the EPU LAR. Each COLR value submitted under the EPU LAR but which are relocated to the COLR as a result of the February 24, 2012, approval are described and evaluated in this safety evaluation. Figure 2.1-1 has been relocated to the COLR.

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[167] ML110550160
[168] ML12003A133
[169] ML120790306

Technical Specification Table 2.2-1, RTS [Reactor Trip System] Instrumentation Trip Setpoints

Current TS (General)

This TS table contains changes to nominal trip setpoint (NTS) and allowable values for RTS setpoints. The NTS values are the limiting safety system setting (LSSS) values that are derived from the analytical values and adjusted to account for the specific instrument uncertainties.

Proposed TS (General) (NOTE: With the issuance of Amendment Nos. 247 and 243, certain values in the table notations for Over temperature ΔT and Overpower ΔT have been relocated to the COLR. See explanation below.)

The nominal trip setpoints and allowable values are proposed to be changed, as shown in the August 29, 2011, letter, for the following functions:

- 2.a Power Range Neutron Flux-High Setpoint
- 5. Overtemperature ΔT—Notes 1 and 2
- 6. Overpower ΔT—Notes 3 and 4
- 10. Reactor Coolant Flow-Low
- 11. Steam Generator Water Level-Low-Low
- 12. Steam/Feedwater Flow Mismatch Coincident with Steam Generator (SG) Water Level-Low
- 15.a Turbine Trip-Emergency Trip Header Pressure

The licensee stated:

> As defined in 10 CFR 50.36, LSSS are settings for automatic protective devices related to those variables having significant safety functions. 10 CFR 50.36 requires that these limiting settings be included in the Technical Specifications.
>
> The NTS values for RTS trip functions in Table 2.2-1 are calculated based on limits from the safety analyses, process limits for the instrumentation, and the instrument loop uncertainties calculated with 95% [percent] probability and 95% confidence to industry standard methodology. The methods used to determine the NTS and Allowable Values and summaries of associated calculations are provided WCAP-17070-P.
>
> The NTS values proposed for TS Table 2.2-1 are values for the nominal trip setpoint and are calculated such that there is 95% probability and 95% confidence that the trip will occur prior to the process variable exceeding the established limit under EPU conditions. Therefore, the assumptions of the safety analyses and their results are protected by the proposed LSSS values.
>
> These LSSS values have been evaluated using methods described in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems, and WCAP-17070-P. In accordance with TSTF[Technical Specifications Task Force]-493 Rev. 4, Option A, Notes (a) and (b) regarding the as-found and as-left

tolerances around the Nominal Trip Setpoints are added to the Channel Calibration and analog channel operational test surveillances associated with the above NTS values in TS Table 4.3-1 (Reactor Trip System Instrumentation Surveillance Requirements). Although TSTF-493 Rev. 4 only requires them to be placed against these surveillance requirements, they are also being added to the affected functions in Table 2.2-1. Since the information for each trip function is spread out over three tables, this approach will enhance the ability of the operator to readily recognize the trip functions affected by the TSTF.

NRC Technical Evaluation

As stated in 10 CFR 50.36(c)(1)(ii)(A), limiting safety system settings for nuclear reactors are settings for automatic protective devices related to those variables having significant safety functions. Where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting must be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded.

The overall setpoint methodology used to establish the above TS values is reviewed as discussed in this SE's Section 2.4. The NRC staff confirms that the trip setpoints assumed in the safety analyses, which were performed using NRC-approved codes and methods, resulted in acceptable postulated reactor system performance. The staff's review of the licensee's transient and accident analyses is discussed in Section 2.8.5 of this SE. Because the staff found the EPU safety analyses, on which the RTS setpoints are based, acceptable, the proposed setpoints are also acceptable.

By letter dated February 21, 2011, FPL submitted a LAR to revise the Turkey Point, Units 3 and 4 TSs to relocate selected figures and values from the TSs to the Core Operating Limits Report COLR. By letter dated February 24, 2012, the NRC staff approved the license amendment and issued Amendment Nos. 247 and 243 for Turkey Point, Units 3 and 4, respectively.

By Letter dated March 15, 2012, FPL identified those COLR TS pages issued in Amendment Nos. 247 and 243 that supersede the EPU application TS pages. In addition, the licensee also stated that the EPU parameters included on these pages will be relocated to the COLR and that the values of the relocated parameters remain unchanged from the values reviewed by the NRC staff for the EPU LAR. Each COLR value submitted under the EPU LAR but which are relocated to the COLR as a result of the February 24, 2012, approval are described and evaluated in this safety evaluation. Certain values in the table notations for Over temperature ΔT and Overpower ΔT have been relocated to the COLR.

Technical Specification 3/4.1.1 Boration Control – Shutdown Margin - Tavg > 200 °F

Current TS

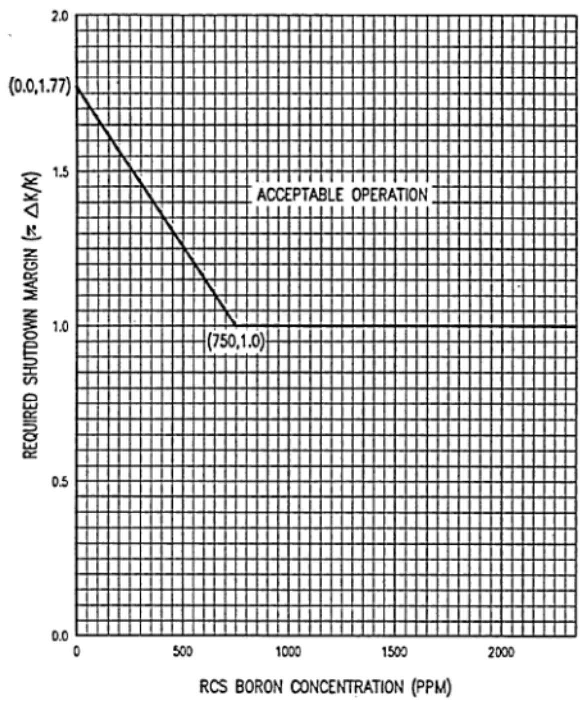
3.1.1.1 The SHUTDOWN MARGIN shall be greater than or equal to the applicable value shown in Figure 3.1-1.

Proposed TS (NOTE: With the issuance of Amendment Nos. 247 and 243, Figure 3.1-1 has been relocated to the COLR. See explanation below.)

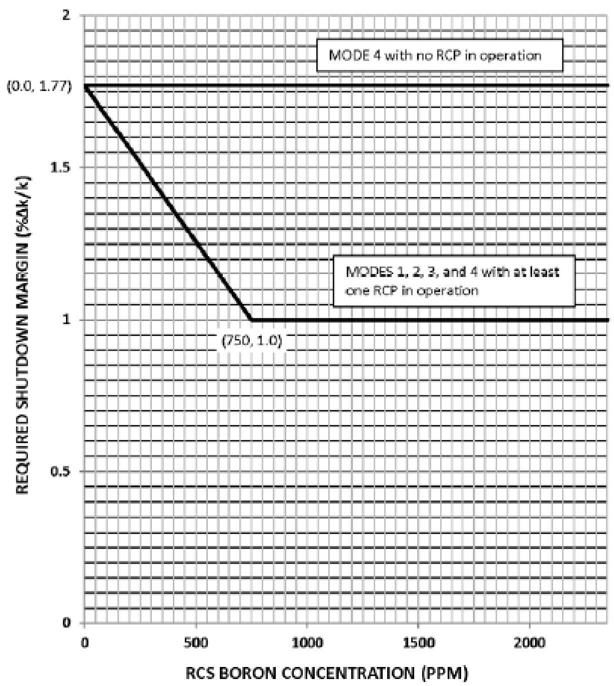
3.1.1.1 The SHUTDOWN MARGIN shall be greater than or equal to the applicable value shown in Figure 3.1-1.

Figure 3.1-1, "Required Shutdown Margin vs Reactor Coolant Boron Concentration," is revised as shown in the figures below to provide a separate curve representing the minimum allowable shutdown margin in Mode 4 when no reactor coolant pumps are operating.

<u>Current:</u>



<u>Proposed:</u>



By letter dated February 21, 2011, FPL submitted a LAR to revise the Turkey Point, Units 3 and 4 TSs to relocate selected figures and values from the TSs to the Core Operating Limits Report COLR. By letter dated February 24, 2012, the NRC staff approved the license amendment and issued Amendment Nos. 247 and 243 for Turkey Point, Units 3 and 4, respectively.

By Letter dated March 15, 2012, FPL identified those COLR TS pages issued in Amendment Nos. 247 and 243 that supersede the EPU application TS pages. In addition, the licensee also stated that the EPU parameters included on these pages will be relocated to the COLR and that the values of the relocated parameters remain unchanged from the values reviewed by the NRC staff for the EPU LAR. Each COLR value submitted under the EPU LAR but which are relocated to the COLR as a result of the February 24, 2012, approval are described and evaluated in this safety evaluation. This figure has been relocated to the COLR.

Technical Specification 3/4.1.1 Boration Control – Shutdown Margin - Tavg ≤ 200°F

Current TS

3.1.1.2 The SHUTDOWN MARGIN shall be greater than or equal to 1% Δk/k.

APPLICABILITY: MODE 5.

ACTION:

With the SHUTDOWN MARGIN less than 1% Δk/k, immediately initiate and continue boration at greater than or equal to 16 gpm [gallons per minute] of a solution containing greater than or equal to 3.0 wt [weight] % (5245 ppm [parts per million]) boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN shall be determined to be greater than or equal to 1% Δk/k:

Proposed TS (NOTE: With the issuance of Amendment Nos. 247 and 243, the values for shutdown margin have been relocated to the COLR. See explanation below.)

3.1.1.2 The SHUTDOWN MARGIN shall be greater than or equal to **1.77 % Δk/k**.

APPLICABILITY: MODE 5.

ACTION:

With the SHUTDOWN MARGIN less than **1.77 % Δk/k**, immediately initiate and continue boration at greater than or equal to 16 gpm of a solution containing greater than or equal to 3.0 wt% (5245 ppm) boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN shall be determined to be greater than or equal to **1.77 % Δk/k**: Basis for the Change: An increase in the minimum allowable shutdown margin for Mode 5 is necessary to assure adequate operator response time is available to identify and terminate an inadvertent dilution event in Mode 5 prior to loss of all shutdown margin.

By letter dated February 21, 2011, FPL submitted a LAR to revise the Turkey Point, Units 3 and 4 TSs to relocate selected figures and values from the TSs to the Core Operating Limits Report COLR. By letter dated February 24, 2012, the NRC staff approved the license amendment and issued Amendment Nos. 247 and 243 for Turkey Point, Units 3 and 4, respectively.

By Letter dated March 15, 2012, FPL identified those COLR TS pages issued in Amendment Nos. 247 and 243 that supersede the EPU application TS pages. In addition, the licensee also stated that the EPU parameters included on these pages will be relocated to the COLR and that the values of the relocated parameters remain unchanged from the values reviewed by the NRC

staff for the EPU LAR. Each COLR value submitted under the EPU LAR but which are relocated to the COLR as a result of the February 24, 2012, approval are described and evaluated in this safety evaluation. The values for shutdown margin have been relocated to the COLR.

Technical Specification 3/4.1.2 Boration Control – Flowpaths - Operating

Current TS

3.1.2.2 The following boron injection flow paths shall be OPERABLE:

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With no boration source path from a boric acid storage tank OPERABLE,

   2. Restore the boration source path from a boric acid storage tank to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 1% Δk/k at 200 °F within the next 6 hours; restore the boration source path from a boric acid storage tank to OPERABLE status within the next 72 hours or be in COLD SHUTDOWN within the next 30 hours.

b. With only one boration source path OPERABLE or the regenerative heat exchanger flow path to the RCS inoperable, restore the required flow paths to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 1% Δk/k at 200 °F within the next 6 hours; restore at least two boration source paths to OPERABLE status within the next 72 hours or be in COLD SHUTDOWN within the next 30 hours.

c. With the boration source path from a boric acid storage tank and the charging pump discharge path via the regenerative heat exchanger inoperable, within one hour initiate boration to a SHUTDOWN MARGIN equivalent to 1% Δk/k at 200 °F and go to COLD SHUTDOWN as soon as possible within the limitations of the boration and pressurizer level control functions of the CVCS.

Proposed TS

3.1.2.2 The following boron injection flow paths shall be OPERABLE:

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With no boration source path from a boric acid storage tank OPERABLE,

   2. Restore the boration source path from a boric acid storage tank to OPERABLE status within **70** hours or be in at least HOT STANDBY and borated to a **boron concentration**

equivalent to at least the required SHUTDOWN MARGIN at COLD SHUTDOWN at 200 °F within the next **8** hours; restore the boration source path from a boric acid storage tank to OPERABLE status within the next 72 hours or be in COLD SHUTDOWN within the next 30 hours.

b. With only one boration source path OPERABLE or the regenerative heat exchanger flow path to the RCS inoperable, restore the required flow paths to OPERABLE status within **70** hours or be in at least HOT STANDBY and borated to a **boron concentration equivalent to at least the required SHUTDOWN MARGIN at COLD SHUTDOWN at 200 °F** within the next **8** hours; restore at least two boration source paths to OPERABLE status within the next 72 hours or be in COLD SHUTDOWN within the next 30 hours.

c. With the boration source path from a boric acid storage tank and the charging pump discharge path via the regenerative heat exchanger inoperable, within one hour initiate boration to a **boron concentration equivalent to the required SHUTDOWN MARGIN at COLD SHUTDOWN at 200 °F** and go to COLD SHUTDOWN as soon as possible within the limitations of the boration and pressurizer level control functions of the CVCS.

Technical Specification 3/4.1.2 Boration Control – Charging Pumps - Operating

<u>Current TS</u>

3.1.2.3 At least two charging pumps shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With only one charging pump OPERABLE, restore at least two charging pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 1% $\Delta k/k$ at 200 °F within 6 hours; restore at least two charging pumps to OPERABLE status within 72 hours or be in COLD SHUTDOWN within the next 30 hours.

<u>Proposed TS</u>

3.1.2.3 At least two charging pumps shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

With only one charging pump OPERABLE, restore at least two charging pumps to OPERABLE status within **70** hours or be in at least HOT STANDBY and borated to a **boron concentration equivalent to at least the required SHUTDOWN MARGIN at COLD SHUTDOWN at 200 °F** within **8** hours; restore at least two charging pumps to OPERABLE status within 72 hours or be in COLD SHUTDOWN within the next 30 hours.

Technical Specification 3/4.1.2 Boration Control – Borated Water Sources - Operating

Current TS

3.1.2.5 The following borated water sources shall be OPERABLE:

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With the required Boric Acid Storage System inoperable verify that the RWST is OPERABLE; restore the system to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours* and borated to a SHUTDOWN MARGIN equivalent to at least 1% $\Delta k/k$ at 200 °F; restore the Boric Acid Storage System to OPERABLE status within the next 72 hours or be in COLD SHUTDOWN within the next 30 hours.

   * If this action applies to both units simultaneously, be in at least HOT STANDBY within the next twelve hours.

Proposed TS

3.1.2.5 The following borated water sources shall be OPERABLE:

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

a. With the required Boric Acid Storage System inoperable verify that the RWST is OPERABLE; restore the system to OPERABLE status within **70** hours or be in at least HOT STANDBY within the next **8** hours* and borated to a **boron concentration equivalent to at least the required SHUTDOWN MARGIN at COLD SHUTDOWN at 200 °F**; restore the Boric Acid Storage System to OPERABLE status within the next 72 hours or be in COLD SHUTDOWN within the next 30 hours.

   * If this action applies to both units simultaneously, be in at least HOT STANDBY within the next **sixteen** hours.

The licensee stated:

> An increase in the minimum allowable shutdown margin for Mode 4 without reactor coolant pumps operating is necessary to assure adequate operator response time is available to identify and terminate an inadvertent dilution event prior to loss of all shutdown margin.
>
> The minimum allowable shutdown margin in Mode 5 (Cold Shutdown) is increased to 1.77 % $\Delta k/k$ as described above to assure adequate operator response time is available to identify and terminate an inadvertent dilution event

prior to loss of all shutdown margin. The change to TS 3.1.2.2 removes the numeric value of minimum shutdown margin at 200 ºF to more clearly convey the objective of the Action Statement to borate to Cold Shutdown conditions in advance of reaching Mode 5 entry conditions.

The minimum allowable shutdown margin in Mode 5 (Cold Shutdown) is increased to 1.77 % Δk/k as described above to assure adequate operator response time is available to identify and terminate an inadvertent dilution event prior to loss of all shutdown margin. The change to TS 3.1.2.5 removes the numeric value of minimum shutdown margin at 200 ºF to more clearly convey the objective of the Action Statement to borate to Cold Shutdown conditions in advance of reaching Mode 5 entry conditions.

In a supplement dated January 10, 2012, the licensee provided the following basis for part of the changes to TS 3.1.2.2, TS 3.1.2.3, and TS 3.1.2.5:

The minimum allowable shutdown margin in Mode 5 (Cold Shutdown) was increased to 1.77 % Δk/k to assure adequate operator response time is available to identify and terminate an inadvertent dilution event prior to loss of all shutdown margin. The change to TS 3.1.2.2[TS 3.1.2.3 and TS 3.1.2.5] increases the required time to borate to the required shutdown margin from 6 hours to 8 hours while maintaining the overall action time at 78 hours by decreasing the required restoration time for a boration source path from 72 hours to 70 hours. This change is necessary to reflect the boration system design capabilities and is considered conservative as it requires earlier initiation of boration.

NRC Technical Evaluation

As stated in 10 CFR 50.36(c)(ii), a limiting condition for operation of a nuclear reactor must be established for, among other things, a process variable, design feature, of operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. The proposed revisions to TS 3.1 will ensure that the shutdown margin is maintained within the limits assumed in the safety analyses for boron dilution events. The staff’s evaluation of these events is discussed in Section 2.8.5.4, “Reactivity and Power Distribution Anomalies,” of this SE. Based on the staff’s acceptance of these safety analyses, the proposed TS revisions are found acceptable.

Technical Specification 3/4.1.1.3, Moderator Temperature Coefficient

Current TS

LCO [Limiting Condition for Operation] 3.1.1.3 The moderator temperature coefficient (MTC) shall be:

d. Less negative than -3.5×10^{-4} Δk/k/°F for the all rods withdrawn, end of cycle life (EOL), RATED THERMAL POWER condition.

SR 4.1.1.3 The MTC shall be determined to be within its limits during each fuel cycle as follows:

b. The MTC shall be measured at any THERMAL POWER and compared to -3.0×10^{-4} $\Delta k/k/°F$ (all rods withdrawn, RATED THERMAL POWER condition) within 7 EFPD after reaching an equilibrium boron concentration of 300 ppm. In the event this comparison indicates the MTC is more negative than -3.0×10^{-4} $\Delta k/k/°F$, the MTC shall be remeasured, and compared to the EOL MTC limit of Specification 3.1.1.3d., at least once per 14 EFPD during the remainder of the fuel cycle.

Proposed TS (NOTE: With the issuance of Amendment Nos. 247 and 243, certain values for the Moderator Temperature Coefficient have been relocated to the COLR. See explanation below.)

LCO 3.1.1.3 The moderator temperature coefficient (MTC) shall be:

d. Less negative than **-4.1×10^{-4}** $\Delta k/k/°F$ for the all rods withdrawn, end of cycle life (EOL), RATED THERMAL POWER condition.

SR 4.1.1.3 The MTC shall be determined to be within its limits during each fuel cycle as follows:

b. The MTC shall be measured at any THERMAL POWER and compared to **-3.5×10^{-4} $\Delta k/k/°F$** (all rods withdrawn, RATED THERMAL POWER condition) within 7 EFPD after reaching an equilibrium boron concentration of 300 ppm. In the event this comparison indicates the MTC is more negative than **-3.5×10^{-4} $\Delta k/k/°F$**, the MTC shall be re-measured, and compared to the EOL MTC limit of Specification 3.1.1.3d., at least once per 14 EFPD during the remainder of the fuel cycle.

The licensee stated:

> The MTC End of Cycle life LCO and Surveillance Tech Spec limits are changed from -3.5×10^{-4} and -3.0×10^{-4} $\Delta k/k/°F$ to -4.1×10^{-4} and -3.5×10^{-4} $\Delta k/k/°F$, respectively, to ensure that sufficient margin exists for this parameter for future cycle bounding analyses. MTC values must remain within the bounds of those used in the accident analysis of the UFSAR Chapter 14 and MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

NRC Technical Evaluation

Paragraph (c)(ii) of 10 CFR 50.36 states that a limiting condition for operation of a nuclear reactor must be established for, among other things, a process variable, design feature, of operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. The MTC is included in this category because its value is an important initial condition in the accident and transient analysis. It is especially important for the reactivity and power distribution anomalies evaluated in SE Section 2.8.5.4.

The proposed changes to the limits on moderator temperature coefficient ensure that the plant performance under AOO and accident conditions will be bounded by the safety analyses supporting the EPU request. The changes are acceptable, because the staff found the EPU safety analyses on which these limits are based acceptable. The staff's review is discussed more fully in SE Sections 2.8.2, "Nuclear Design," and 2.8.5, "Accident and Transient Analyses."

By letter dated February 21, 2011, FPL submitted a LAR to revise the Turkey Point, Units 3 and 4 TSs to relocate selected figures and values from the TSs to the Core Operating Limits Report COLR. By letter dated February 24, 2012, the NRC staff approved the license amendment and issued Amendment Nos. 247 and 243 for Turkey Point, Units 3 and 4, respectively.

By Letter dated March 15, 2012, FPL identified those COLR TS pages issued in Amendment Nos. 247 and 243 that supersede the EPU application TS pages. In addition, the licensee also stated that the EPU parameters included on these pages will be relocated to the COLR and that the values of the relocated parameters remain unchanged from the values reviewed by the NRC staff for the EPU LAR. Each COLR value submitted under the EPU LAR but which are relocated to the COLR as a result of the February 24, 2012, approval are described and evaluated in this safety evaluation. Only the maximum upper limit for MTC shall remain in the TSs. Other values for MTC have been relocated to the COLR.

Technical Specification 3/4.1.2.1, Boration Systems, Flow Path-Shutdown
Technical Specification 3/4.1.2.2, Boration Systems, Flow Path-Operating

Current TS

SR 4.1.2.1/2 At least one of the above required flow paths shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that the temperature of the rooms containing flow path components is greater than or equal to 55°F when a flow path from the boric acid tanks is used, and

Proposed TS

SR 4.1.2.1/2 At least one of the above required flow paths shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that the temperature of the rooms containing flow path components is greater than or equal to **62°F** when a flow path from the boric acid tanks is used, and

The licensee stated:

> For EPU, the minimum temperature of the rooms containing flow path components when a flow path from the boric acid tanks is used is increased to ensure the solubility of the boron solution associated with the increased boron concentration. The minimum temperature is based on the solubility of the increased maximum concentration of boric acid in the boric acid storage tanks of 4.0%, according to the solubility table in WCAP-1570, plus 5°F for instrument uncertainty. Maintaining the room temperature above the solubility temperature

will ensure that the boric acid storage system will remain operable at all EPU concentrations.

NRC Technical Evaluation

Paragraph (c)(3) of 10 CFR 50.36 defines surveillance requirements as requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

The proposed change to the boration systems surveillance requirement (SR) will increase the minimum temperature for rooms containing boration flow path components. The licensee determined the appropriate table using the boric acid solubility limits and including a margin for instrument uncertainty. The requirement will ensure that flow path components do not fall to a temperature that would allow the boric acid to precipitate out of solution, a condition which could block the flow path or reduce the concentration of the influent boric acid solution, resulting in unintended reactivity effects. On the basis that the revised surveillance requirement ensures that the boration flow path temperature will preclude precipitation, the staff finds the proposed revision acceptable. It complies with 10 CFR 50.36(c)(3) because it assures that the necessary quality of systems and components is maintained.

Technical Specification 3.1.2.5, Borated Water Sources - Operating

Current TS

LCO 3.1.2.5 The following borated water sources shall be OPERABLE:

a. A Boric Acid Storage System with:

    3) A minimum boric acid tanks room temperature of 55°F.

b. The refueling water storage tank (RWST) with:

    2) A minimum boron concentration of 1950 ppm,

Action:

c. With the boric acid tank inventory concentration greater than 3.5 wt%, verify that the boric acid solution temperature for boration sources and flow paths is greater than the solubility limit for the concentration.

Figure 3.1-2 Boric Acid Tank Minimum Volume (1) – Modes 1, 2, 3, and 4 (Minimum BAT Volume vs. BAT Inventory Concentration) (figure omitted)

SR 4.1.2.5 Each borated water source shall be demonstrated OPERABLE:

a. At least once per 7 days by:

3) Verifying that the temperature of the boric acid tanks room is greater than or equal to 55 °F, when it is the source of borated water.

Proposed TS

LCO 3.1.2.5 The following borated water sources shall be OPERABLE:

a. A Boric Acid Storage System with:

3) A minimum boric acid tanks room temperature of **62 °F**.

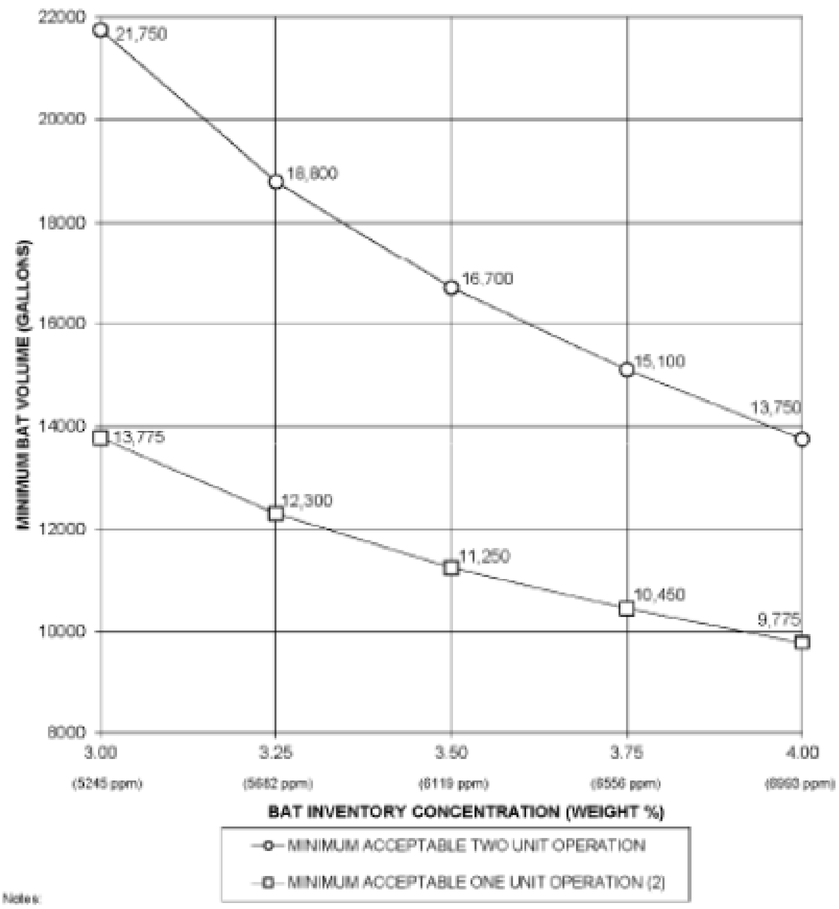
b. The refueling water storage tank (RWST) with:

2) A boron concentration **between 2400 ppm and 2600 ppm**.

Action:

c. With the boric acid tank inventory concentration greater than **4.0 wt%** verify that the boric acid solution temperature for boration sources and flow paths is greater than the solubility limit for the concentration.

Figure 3.1-2 Boric Acid Tank Minimum Volume (1) – Modes 1, 2, 3, and 4 (Minimum BAT Volume vs BAT Inventory Concentration) is revised as shown below



Notes:

(1) Combined volume of all available boric acid tanks assuming RWST boron concentration between 2400 ppm and 2600 ppm.
(2) Includes 2000 gallons for the shutdown unit.

SR 4.1.2.5 Each borated water source shall be demonstrated OPERABLE:

a. At least once per 7 days by:

3) Verifying that the temperature of the boric acid tanks room is greater than or equal to **62°F** when it is the source of borated water.

The licensee stated:

> The EPU boron delivery capability of the Chemical and Volume Control System during cooldown sets new boron concentration limits that are achieved in the RCS with the boric acid tanks and refueling water storage tanks at conservative temperatures and levels. The resulting minimum achievable Reactor Coolant System boron concentration limits are used in the Reload Safety Analysis

> Checklist to ensure adequate reactivity shutdown margin is available for any post shutdown time. The minimum boron concentration in the Boric Acid Storage System, provided in a curve of boric acid tank volume versus concentration, has been increased and the minimum concentration in the RWST has been raised from 1950 ppm to 2400 ppm, with a new maximum concentration specified for 2600 ppm to preclude boron precipitation in the core. These increases create acceptable margin to the core design limit.
>
> For EPU, the minimum temperature of the boric acid tanks room is increased to ensure the solubility of the boron solution associated with the increased boron concentration. The minimum temperature is based on the solubility of the increased maximum concentration of boric acid in the boric acid storage tanks of 4.0%, according to the solubility table in WCAP-1570, plus 5°F for instrument uncertainty. Maintaining the room temperature above the solubility temperature will ensure that the boric acid storage system will remain operable at all EPU concentrations.
>
> ACTION statement c. is being revised to reflect the increase in the maximum boron concentration of the boric acid storage tanks from 3.5 wt% to 4.0 wt%.

In a supplement dated January 10, 2012 the licensee provided the above Figure 3.1-2 that included tank level instrument uncertainty and the following basis for the change.

> The Boric Acid Tank Minimum Volume curve (submitted October 21, 2010) did not include tank level instrument uncertainty and is being revised to assure indicated level remained conservative. The total volumetric uncertainty including level measurement and minimum vortex volume has been determined to be limited to 600 gallons so that the minimum volume curves in Figure 3.1-2 have been revised to add 600 gallons for one unit operation and 1200 gallons for two unit operation.

NRC Technical Evaluation

As stated in 10 CFR 50.36(c)(ii), a limiting condition for operation (LCO) of a nuclear reactor must be established for, among other things, a process variable, design feature, of operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. 10 CFR 50.36(c)(3) defines surveillance requirements as requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met.

The proposed LCO revisions will ensure two things: (1) the boric acid solution remains in liquid form and can be injected into the RCS, and (2) the boric acid concentration is high enough to ensure that the reactor core remains shutdown and subcritcal, consistent with the PTN reactivity control design criteria and the accident analyses, but low enough to preclude a boric acid precipitation event that could obstruct adequate core cooling as required by 10 CFR 50.46(a)(1)(i) and (b)(4) and (b)(5). Therefore, the LCO revisions are acceptable because they are consistent with the intent of 10 CFR 50.36(c)(ii). The applicable safety analyses are

evaluated in Section 2.8.5.6.3, “Emergency Core Cooling System and Loss of Coolant Accidents,” of this SE.

The proposed change to the boric acid tank SR will increase the minimum temperature for the tank. The licensee determined the appropriate value using the boric acid solubility limits and including a margin for instrument uncertainty. The requirement will ensure that flow path components do not fall to a temperature that would allow the boric acid to precipitate out of solution, a condition which could block the flow path or reduce the concentration of the influent boric acid solution, resulting in unintended reactivity effects. The revised surveillance requirement ensures that the Boric Acid Tank temperature will preclude precipitation. On this basis, the staff finds the proposed revision acceptable. It complies with 10 CFR 50.36(c)(3) because it assures that the necessary quality of systems and components is maintained.

Technical Specification 3.2.5, DNB Parameters

Current TS

LCO 3.2.5 The following DNB-related parameters shall be maintained within the following limits:

a. Reactor Coolant System Tavg ≤ 581.2°F

b. Pressurizer Pressure ≥ 2200 psig*, and

c. Reactor Coolant System Flow ≥ 264,000 gpm

Proposed TS (NOTE: With the issuance of Amendment Nos. 247 and 243, the numerical values for reactor coolant system Tavg and pressurizer pressure have been relocated to the COLR. See explanation below.)

LCO 3.2.5 The following DNB-related parameters shall be maintained within the following limits:

a. Reactor Coolant System Tavg ≤ **585°F**

b. Pressurizer Pressure ≥ **2204 psig*** and

c. Reactor Coolant System Flow ≥ **270,000** gpm

The licensee stated:

> The EPU revised limits for the DNB-related parameters assure that each of the parameters are maintained within the normal steady-state envelope of operation assumed in the transient and accident analyses. The limits are consistent with the UFSAR assumptions and have been analytically demonstrated adequate to maintain a minimum Departure from Nucleate Boiling Ratio (DNBR) above the applicable design limits throughout each analyzed transient.

NRC Technical Evaluation

As stated in 10 CFR 50.36(c)(ii), a limiting condition for operation of a nuclear reactor must be established for, among other things, a process variable, design feature, of operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. Keeping the DNB ratio within its limit ensures that fuel cladding integrity is maintained; the proposed revisions ensure that the reactor coolant system operates in a condition in which the DNB safety analyses are valid.

The DNB analyses are discussed and evaluated in SE Section 2.8.3, “Thermal and Hydraulic Design,” and the transient analyses are evaluated in SE Section 2.8.5, “Accident and Transient Analyses.” As discussed in those SE sections, the staff finds the licensee’s DNB safety analyses and results acceptable, and on this basis, the proposed LCO revision is acceptable for the proposed EPU.

By letter dated February 21, 2011, FPL submitted a LAR to revise the Turkey Point, Units 3 and 4 TSs to relocate selected figures and values from the TSs to the Core Operating Limits Report COLR. By letter dated February 24, 2012, the NRC staff approved the license amendment and issued Amendment Nos. 247 and 243 for Turkey Point, Units 3 and 4, respectively.

By Letter dated March 15, 2012, FPL identified those COLR TS pages issued in Amendment Nos. 247 and 243 that supersede the EPU application TS pages. In addition, the licensee also stated that the EPU parameters included on these pages will be relocated to the COLR and that the values of the relocated parameters remain unchanged from the values reviewed by the NRC staff for the EPU LAR. Each COLR value submitted under the EPU LAR but which are relocated to the COLR as a result of the February 24, 2012, approval are described and evaluated in this safety evaluation. The numerical values for reactor coolant system Tavg and pressurizer pressure have been relocated to the COLR.

Technical Specification Table 3.3-3 ESFAS Instrumentation Trip Setpoints

Current TS (General)

This Technical Specification table contains changes to Nominal Trip Setpoint (NTS) and Allowable Values for ESFAS setpoints. The NTS values are the LSSS values that are derived from the analytical values and adjusted to account for the specific instrument uncertainties. The Allowable Values and Nominal Trip Setpoints for selected functions in Technical Specification Table 3.3-3 (ESFAS Instrumentation Trip Setpoints) are being revised to reflect changes resulting from EPU and implementation of the methodology of WCAP-17070-P.

Proposed TS (General)

The ESFAS Nominal Trip Setpoints and Allowable Values are proposed to be changed for the following functions:

1.f Safety Injection (SI)-Steam Line Flow-High Coincident with Steam Generator Pressure-Low

4.d Steam Line Isolation-Steam Line Flow-High Coincident with Steam Line Pressure –Low or T_{avg}-Low

5.c Feedwater Isolation-Steam Generator Water level High-High

6.b Auxiliary Feedwater(3)-Steam Generator Water Level-Low-Low

7.b Loss of Power-480V Load Centers Undervoltage

Load Center	Allowable Value#	Trip Setpoint
3A	[ ]	430V +/-3V (10 sec +/-1 sec delay)
3B	[ ]	438V +/-3V (10 sec +/-1 sec delay)
3C	[ ]	434V +/-3V (10 sec +/-1 sec delay)
3D	[ ]	434V +/-3V (10 sec +/-1 sec delay)
4A	[ ]	435V +/-3V (10 sec +/-1 sec delay)
4B	[ ]	434V +/-3V (10 sec +/-1 sec delay)
4C	[ ]	434V +/-3V (10 sec +/-1 sec delay)
4D	[ ]	430V +/-3V (10 sec +/-1 sec delay)

7.c Loss of Power-480V Load Centers Degraded Voltage

Load Center	Allowable Value#	Trip Setpoint
3A	[ ]	424V +/-3V (60 sec +/-30 sec delay)
3B	[ ]	427V +/-3V (60 sec +/-30 sec delay)
3C	[ ]	437V +/-3V (60 sec +/-30 sec delay)
3D	[ ]	435V +/-3V (60 sec +/-30 sec delay)
4A	[ ]	430V +/-3V (60 sec +/-30 sec delay)
4B	[ ]	436V +/-3V (60 sec +/-30 sec delay)
4C	[ ]	434V +/-3V (60 sec +/-30 sec delay)
4D	[ ]	434V +/-3V (60 sec +/-30 sec delay)

The licensee stated:

> As defined in 10 CFR 50.36, LSSS are settings for automatic protective devices related to those variables having significant safety functions. 10 CFR 50.36 requires that these limiting settings be included in the Technical Specifications.
>
> The NTS values proposed for TS Table 3.3-3 are values for the nominal trip setpoint and are calculated such that there is 95% probability and 95% confidence that the interlock, permissive or block function will occur prior to the process variable exceeding the established limit and ensures the interlock, permissive or block function will occur in accordance with the assumptions of the analyses. Therefore, the assumptions of the safety analyses and results are protected by proposed LSSS values. The methods used to determine NTS values and summaries of calculations are provided in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems, and WCAP-17070-P. These LSSS values have been evaluated under EPU conditions using

> methods described in LR Section 2.4.1, Reactor Protection, Safety Features Actuation, and Control Systems, and WCAP-17070-P.
>
> NRC Technical Evaluation

As stated in 10 CFR 50.36(c)(1)(ii)(A), limiting safety system settings for nuclear reactors are settings for automatic protective devices related to those variables having significant safety functions. The LSSS are setpoints for equipment to actuate, which is necessary to mitigate the effects of design basis events. The LSSS values are derived from safety analyses, which are evaluated by the staff in Section 2.8.5 of this SE. Based on the staff's acceptable findings discussed in that section, the staff finds the proposed trip setpoints acceptable. The setpoint methodology and uncertainties are discussed and evaluated in Section 2.4 of this SE.

Technical Specification 3.4.2 RCS Safety Valves – Shutdown and Operating

Current TS

SHUTDOWN

LCO 3.4.2.1 A minimum of one pressurizer Code safety valve shall be OPERABLE* with a lift setting of 2485 psig [pounds per square inch gauge] + 2%, -3%.** ***

OPERATING

LCO 3.4.2.2 All pressurizer Code safety valves shall be OPERABLE with a lift setting of 2485 psig + 2%, -3%.* **

Proposed TS

SHUTDOWN

LCO 3.4.2.1 A minimum of one pressurizer Code safety valve shall be OPERABLE* with a lift setting of **2465 psig** + 2%, -3%.** ***

OPERATING

LCO 3.4.2.2 All pressurizer Code safety valves shall be OPERABLE with a lift setting of **2465 psig** + 2%, -3%.* **

The licensee stated:

> To meet an RCS pressure limit of 2748.5 psia for a Loss of External Electrical Load/Turbine Trip event at EPU conditions, the pressurizer safety valve lift setting was reduced.

NRC Technical Evaluation

Paragraph (c)(3) of 10 CFR 50.36) states that a limiting condition for operation of a nuclear reactor must be established for, among other things, a process variable, design feature, of operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. This LCO ensures that the reactor coolant pressure boundary remains intact for the design basis events that cause the RCS pressure to increase. The LCO is based on the limiting pressurization transient analysis. The staff's evaluation of the limiting pressurization event is described in Section 2.8.5.2 of this SE. Based on the acceptable results of the safety analysis, the staff finds the proposed LCO acceptable.

Technical Specification 3.4.9.3 Overpressure Mitigating Systems

Current TS

LCO 3.4.9.3 The high pressure safety injection flow paths to the Reactor Coolant System (RCS) shall be isolated, and at least one of the following Overpressure Mitigating Systems shall be OPERABLE:

a. Two power-operated relief valves (PORVs) with a lift setting of 468 psig, or

Proposed TS

LCO 3.4.9.3 The high pressure safety injection flow paths to the Reactor Coolant System (RCS) shall be isolated, and at least one of the following Overpressure Mitigating Systems shall be OPERABLE:

a. Two power-operated relief valves (PORVs) with a lift setting of **448 psig**, or

The license stated:

> The design basis mass injection flow rate has increased slightly at EPU conditions. Additionally, the differential pressure between the reactor vessel and the hot leg pressure transmitters has increased from 57.0 to 57.4 psig, and the existing P/T limits for 48 EFPY have changed for the proposed EPU. There are no significant changes to the RCS volumes to Turkey Point Units 3 and 4 components as part of the proposed EPU. The existing OMS setpoint analysis was revised to include the effects of these changes on the existing OMS PORV setpoint for the proposed EPU. The methodology and computer code used in the analysis are the same as for the existing analysis. The existing OMS PORV setpoint was revised from 468 psig to 448 psig.

NRC Technical Evaluation

This TS change is explicitly evaluated as discussed in this SE's Section 2.8.4.3, "Overpressure Protection During Low-Temperature Operation." The staff found the change acceptable.

Technical Specification 3.5.1, Accumulators

Current TS

Each accumulator shall be demonstrated OPERABLE:

SR 4.5.1.1.b. At least once per 31 days and within 6 hours after each solution volume increase of greater than or equal to 1% of tank volume by verifying the boron concentration of the solution in the water-filled accumulator is between 1950 and 2350 ppm;

Proposed TS

Each accumulator shall be demonstrated OPERABLE:

SR 4.5.1.1.b. At least once per 31 days and within 6 hours after each solution volume increase of greater than or equal to 1% of tank volume by verifying the boron concentration of the solution in the water-filled accumulator is between **2300 ppm and 2600 ppm**;

The licensee stated:

> The accumulator minimum boron concentration was increased to ensure the core will remain subcritical following a LOCA [loss-of-coolant accident] under EPU conditions. The analysis also confirmed that the proposed accumulator maximum boron concentration would remain soluble and preclude precipitation in the core.

NRC Technical Evaluation

As stated in 10 CFR 50.36(c)(ii), a limiting condition for operation of a nuclear reactor must be established for, among other things, a process variable, design feature, of operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. The accumulator boron concentration falls into this category because it is vital to holding the core subcritical following a postulated LOCA, and thus ensuring compliance with the acceptance criteria promulgated by 10 CFR 50.46.

The proposed LCO revisions will ensure two things: (1) the boric acid solution remains in liquid form and can be injected into the RCS, and (2) the boric acid concentration is high enough to ensure that the reactor core remains shutdown and subcritcal, consistent with the PTN reactivity control design criteria and the accident analyses, but low enough to preclude a boric acid precipitation event that could obstruct adequate core cooling as required by 10 CFR 50.46(a)(1)(i) and (b)(4) and (b)(5). Therefore, the LCO revisions are acceptable because they are consistent with the intent of 10 CFR 50.36(c)(ii). The applicable safety analyses are evaluated in Section 2.8.5.6.3, “Emergency Core Cooling System and Loss of Coolant Accidents,” of the staff’s SE.

Technical Specification 3.5.4, Refueling Water Storage Tank

Current TS

LCO 3.5.4 For single Unit operation, one refueling water storage tank (RWST) shall be OPERABLE or for dual Unit operation two RWSTs shall be OPERABLE with:

b. A minimum boron concentration of 1950 ppm of boron,

Proposed TS

LCO 3.5.4 For single Unit operation, one refueling water storage tank (RWST) shall be OPERABLE or for dual Unit operation two RWSTs shall be OPERABLE with:

b. A boron concentration between **2400 ppm and 2600 ppm**

The licensee stated:

> The RWST minimum boron concentration value was increased to between 2400 ppm and 2600 ppm. The minimum boron concentration has been raised to create an acceptable margin to the core design limit while a maximum has been added to ensure that boric acid precipitation in the core is precluded. The resulting sump boron concentration, which is calculated as a function of the pre-LOCA RCS boron concentration, is reviewed for each cycle-specific core design to confirm that adequate boron exists to maintain subcriticality in the long-term post-LOCA environment at EPU conditions.

NRC Technical Evaluation:

As stated in 10 CFR 50.36(c)(ii), a limiting condition for operation of a nuclear reactor must be established for, among other things, a process variable, design feature, of operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. The RWST boron concentration falls into this category because it is vital to holding the core subcritical following a postulated LOCA, and thus ensuring compliance with the acceptance criteria promulgated by 10 CFR 50.46.

The proposed LCO revisions will ensure two things: (1) the boric acid solution remains in liquid form and can be injected into the RCS, and (2) the boric acid concentration is high enough to ensure that the reactor core remains shutdown and subcritcal, consistent with the PTN reactivity control design criteria and the accident analyses, but low enough to preclude a boric acid precipitation event that could obstruct adequate core cooling as required by 10 CFR 50.46(a)(1)(i) and (b)(4) and (b)(5). Therefore, the LCO revisions are acceptable because they are consistent with the intent of 10 CFR 50.36(c)(ii). The applicable safety analyses are evaluated in Section 2.8.5.6.3, “Emergency Core Cooling System and Loss of Coolant Accidents,” of the staff’s SE.

Technical Specification 3.6.1.4 Containment Systems - Internal Pressure

Current TS

Primary containment internal pressure shall be maintained between -2 and +3 psig.

Proposed TS

Primary containment internal pressure shall be maintained between -2 and **+1 psig**.

The Licensee stated:

> Additional margin between the design basis containment pressure and the peak design basis containment pressure was required as a result of the EPITOME M&E/Containment Analysis error. A lower-maximum primary containment internal pressure of +1 psig is used as an initial condition in both the LOCA and MSLB containment integrity analyses and results in lower post accident peak containment pressures. The lower containment pressure is more restrictive and will assure that the accident peak containment pressure remains within design limits.

Technical Specification 3.4.6.1 Reactor Coolant System Leakage - Leakage Detection Systems

Current TS

The following Reactor Coolant System Leakage Detection Systems shall be OPERABLE:

a. The Containment Atmosphere Gaseous or Particulate Radioactivity Monitoring System...

Action:

a. With both the Particulate and Gaseous Radioactivity Monitoring Systems inoperable, operation may continue for up to 7 days provided:

> (4) Containment Purge, Exhaust and Instrument Air Bleed valves are maintained closed.

Proposed TS

The following Reactor Coolant System Leakage Detection Systems shall be OPERABLE:

a. The Containment Atmosphere Gaseous or Particulate Radioactivity Monitoring System...

Action:

a. With both the Particulate and Gaseous Radioactivity Monitoring Systems inoperable, operation may continue for up to 7 days provided:

(4) Containment Purge, Exhaust and Instrument Air Bleed valves are maintained closed.**

****Instrument Air Bleed Valves may be opened intermittently under administrative controls.**

The licensee stated:

> Isolation of the containment purge supply, purge exhaust, and instrument air bleed flow paths are required due to the inoperability of both containment particulate and gaseous radiation monitors but intermittent opening of the instrument air bleed valves under administrative control is desirable during the 7 day allowed outage time in order to maintain the containment internal pressure within the limits of TS 3.6.1.4. This action is consistent with the provision in the Notes of NUREG- 1431, Standard Technical Specifications (STS) for Westinghouse Plants, Section 3.6.3 on Containment Isolation Valves which state that penetration flow paths, except for the purge supply and exhaust flow paths, may be unisolated intermittently under administration controls.

Technical Specification Table 3.3-4 Radiation Monitoring Instrumentation for Plant Operations, Action 26

- **Function Ia, Containment Atmosphere Radioactivity-High, and**
- **Function 1b, RCS Leakage Detection Particulate or Gaseous Radioactivity-High**

Current TS

Action 26 - In MODES 1 thru 4: With both the Particulate and Gaseous Radioactivity Monitoring Systems inoperable, operation may continue for up to 7 days provided:

4) Containment Purge, Exhaust and Instrument Air Bleed Valves are maintained closed.

Proposed TS

Action 26 - In MODES 1 thru 4: With both the Particulate and Gaseous Radioactivity Monitoring Systems inoperable, operation may continue for up to 7 days provided:

4)Containment Purge, Exhaust and Instrument Air Bleed valves are maintained closed.**

****Instrument Air Bleed Valves may be opened intermittently under administrative controls.**

The licensee stated:

> See discussion under TS 3.4.6.1 above.

NRC Technical Evaluation

The staff reviewed the licensee's proposed changes regarding TS 3.6.1.4 Containment Systems - Internal Pressure, TS 3.4.6.1 Reactor Coolant System Leakage - Leakage Detection Systems, and TS Table 3.3-4 Radiation Monitoring Instrumentation for Plant Operations, Action 26. Regarding TS 3.4.6.1 Reactor Coolant System Leakage - Leakage Detection Systems and TS Table 3.3-4 Radiation Monitoring Instrumentation for Plant Operations, Action 26, add an allowance for the instrument air bleed valves to be opened intermittently under administrative control during the 7-day allowed outage time with both the Particulate and Gaseous Radioactivity Monitoring Systems inoperable, in order to maintain the containment internal pressure within the limits of TS 3.6.1.4. The staff finds these changes acceptable, based on this action being consistent with the provision in the Notes of NUREG-1431, Standard Technical Specifications (STS). Additional staff discussion is in Section 2.6 of this SE.

Technical Specification Table 3.7-1
Maximum Allowable Power Level with Inoperable
Steam Line Safety Valves During Three Loop Operation

Current TS

Table 3.7-1
Maximum Allowable Power Level With
Inoperable Steam Line Safety Valves During Three Loop Operation

Maximum Number of Inoperable Safety Valves on Any Operating Steam Generator	**Maximum Allowable Power Level (Percent of Rated Thermal Power)**
1	53
2	33
3	14

Proposed TS

Table 3.7-1
Maximum Allowable Power Level With
Inoperable Steam Line Safety Valves During Three Loop Operation

Maximum Number of Inoperable Safety Valves on Any Operating Steam Generator	**Maximum Allowable Power Level (Percent of Rated Thermal Power)**
1	**44**
2	**27**
3	**10**

The licensee stated:

> The analyses related to the effects of EPU on overpressure protection capability during power operation were determined to adequately account for the effects of

> the proposed EPU and concludes the overpressure protection features will continue to provide adequate protection to meet the requirements of its current licensing basis with changes in maximum allowable power level related to the number of inoperable MSSV's as shown in the table. Lower maximum allowable power levels are required to prevent exceeding a main steam system pressure limit of 1208.5 psia for a loss of external electrical load/turbine trip with less than 4 operable MSSVs per steam generator.

NRC Technical Evaluation

This TS change request is evaluated together with requested changes to TS Table 3.7-2, below.

Technical Specification Table 3.7-2 Steam Line Safety Valves Per Loop

Current TS

Table 3.7-2
Steam Line Safety Valves Per Loop

Valve Number				Lift Setting (± 3%* **)	Orifice Size Square Inches
	Loop A	Loop B	Loop C		
1.	RV1400	RV1405	RV1410	1085 psig	16
2.	RV1401	RV1406	RV1411	1100 psig	16
3.	RV1402	RV1407	RV1412	1115 psig	16
4.	RV1403	RV1408	RV1413	1130 psig	16

Proposed TS

Table 3.7-2
Steam Line Safety Valves Per Loop

Valve Number				Lift Setting (± 3%* **)	Orifice Size Square Inches
	Loop A	Loop B	Loop C		
1.	RV1400	RV1405	RV1410	1085 psig	16
2.	RV1401	RV1406	RV1411	1100 psig	16
3.	RV1402	RV1407	RV1412	**1105 psig**	16
4.	RV1403	RV1408	RV1413	**1105 psig**	16

The licensee stated:

> The results of the loss-of-electrical-load/turbine-trip analysis demonstrate that the secondary system pressure limits are met at the proposed EPU conditions when the nominal lift settings of the two highest main steam safety valves are lowered. To meet a main steam system pressure limit of 1208.5 psia for a loss of external

electrical load/turbine trip event, the nominal lift settings of MSSVs RV 1402, 1403, 1407, 1408, 1412, and 1413 were reduced. Lower maximum allowable power levels are required to prevent exceeding a main steam system pressure limit of 1208.5 psia for a loss of external electrical load/turbine trip with less than 4 operable MSSVs per steam generator.

NRC Technical Evaluation

TS Table 3.7-1 and 3.7-2 correspond to LCO 3.7.1.1, “Turbine Cycle Safety Valves.” The LCO requires all main steam line Code safety valves associated with each steam generator to be operable with the lift settings specific in Table 3.7-2. 10 CFR 50.36(c)(2)(ii) states that a limiting condition for operation of a nuclear reactor must be established for, among other things, a process variable, design feature, of operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. Paragraph (c)(2)(i) states that, when a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the TS until the condition can be met.

Table 3.7-1 lists the required actions that apply to various possible conditions where LCO 3.7.1.1 may not be met. The table specifies the peak allowable power level associated with up to three main steam safety valves inoperable. The peak power levels were determined with the safety analysis that is evaluated in Section 2.8.5.2 of this SE. Based on the staff’s acceptance of the applicable safety analyses, the staff finds the revised table entries acceptable.

Table 3.7-2 provides the required lift settings for the main steam safety valves. The entries in this table add specificity to the LCO, because the main steam safety valve lift settings are based on the safety analyses that are evaluated in Section 2.8.5.2 of this SE. Because the staff finds the safety analyses, which assume the values identified in Table 3.7-2 as initial conditions, acceptable, the proposed revision to table 3.7-2 is also acceptable.

Technical Specification 3.9.1 Refueling Operations – Boron Concentration

Current TS

LCO 3.9.1 The boron concentration of all filled portions of the Reactor Coolant System and the refueling canal shall be maintained uniform and sufficient to ensure that the more restrictive of the following reactivity conditions is met; either:

a. A K_{eff} of 0.95 or less, or

b. A boron concentration of greater than or equal to 1950 ppm.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at greater than or equal to 16 gpm of a solution containing greater than or

equal to 3.0 wt% (5245 ppm) boron or its equivalent until K_{eff} is reduced to less than or equal to 0.95 or the boron concentration is restored to greater than or equal to 1950 ppm, whichever is the more restrictive.

Proposed TS

LCO 3.9.1 The boron concentration of all filled portions of the Reactor Coolant System and the refueling canal shall be maintained uniform and sufficient to ensure that the more restrictive of the following reactivity conditions is met; either:

a. A K_{eff} of 0.95 or less, or

b. A boron concentration of greater than or equal to **2300** ppm.

ACTION:

With the requirements of the above specification not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate boration at greater than or equal to 16 gpm of a solution containing greater than or equal to 3.0 wt% (5245 ppm) boron or its equivalent until K_{eff} is reduced to less than or equal to 0.95 or the boron concentration is restored to greater than or equal to **2300** ppm, whichever is the more restrictive.

The licensee stated:

> The increase in the boron concentration from 1950 ppm to 2300 ppm will ensure that the reactor remains subcritical during core alterations and that a uniform boron concentration is maintained for reactivity control in the water volume having direct access to the reactor vessel even assuming a boron dilution incident.

NRC Technical Evaluation

As stated in 10 CFR 50.36(c)(2)(ii), a limiting condition for operation of a nuclear reactor must be established for, among other things, a process variable, design feature, of operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. The above LCO ensures that boron concentrations remain within analyzed conditions, and that adequate operator intervention time is available to stop a boron dilution event before shutdown margin is lost. The above TS revision is acceptable based on the staff's acceptable findings discussed in Section 2.8.5.4, "Reactivity and Power Distribution Anomalies," of this SE.

Technical Specification 3.9.14 Refueling Operations – Spent Fuel Storage

Current TS

LCO 3.9.14 The following conditions shall apply to spent fuel storage:

a. The minimum boron concentration in the Spent Fuel Pit shall be 1950 ppm.

ACTION:

a. With boron concentration in the Spent Fuel Pit less than 1950 ppm, suspend movement of spent fuel in the Spent Fuel Pit and initiate action to restore boron concentration to 1950 ppm or greater.

SR 4.9.14 The boron concentration of the Spent Fuel Pit shall be verified to be 1950 ppm or greater at least once per month.

Proposed TS

LCO 3.9.14 The following conditions shall apply to spent fuel storage:

a. The minimum boron concentration in the Spent Fuel Pit shall be **2300 ppm**.

ACTION:

a. With boron concentration in the Spent Fuel Pit less than **2300 ppm**, suspend movement of spent fuel in the Spent Fuel Pit and initiate action to restore boron concentration to **2300 ppm** or greater.

SR 4.9.14 The boron concentration of the Spent Fuel Pit shall be verified to be **2300 ppm** or greater at least once per month.

The licensee stated:

> Although the criticality analysis (Attachment 10) assumed 1600 ppm in the Spent Fuel Pit to assure k_{eff} < 0.95 under the worst case accident conditions at EPU, the higher boron concentration of 2300 ppm is proposed because, during refueling, the water volume in the Spent Fuel Pit, the transfer canal, the refueling canal and the reactor vessel form a single mass. The proposed value provides significant margin to this requirement.

NRC Technical Evaluation

As stated in 10 CFR 50.36(c)(2)(ii), a limiting condition for operation of a nuclear reactor must be established for, among other things, a process variable, design feature, of operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. The above LCO ensures that boron concentrations remain within analyzed conditions, and that adequate operator intervention time is available to stop a boron dilution event. The above TS revision is acceptable based on the licensee's application dated August 5, 2010, Fuel Criticality Analysis, and the staff's approval dated October 31, 2011.

Technical Specification Table 5.6-1 Component Cyclic or Transient Limits

Current TS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor Coolant System	200 heatup cycles at ≤ 100°F/h and 200 cooldown cycles at ≤ 100°F/h	Heatup cycle -Tave from ≤ 200°F to ≥550°F Cooldown cycle -Tave from ≥550°F to ≤ 200°F
	200 pressurizer cooldown cycles at ≤ 200°F/h	Pressurizer cooldown cycle temperature from ≥ 650°F to ≤ 200°F
	80 loss of load cycles, without immediate Turbine or Reactor trip	≥ 15% of RATED THERMAL POWER to 0% of RATED THERMAL POWER
	40 cycles of loss-of-offsite A.C. electrical power	Loss-of-offsite A.C. electrical ESF Electrical System
	80 cycles of loss of flow in one reactor coolant loop	Loss of only one reactor coolant pump
	400 reactor trip cycles	100% to 0% of RATED THERMAL POWER
	150 leak tests	Pressurized to ≥ 2435 psig
	5 hydrostatic pressure tests	Pressurized to ≥ 3100 psig
Secondary Coolant System	6 loss of secondary pressure	Loss of secondary pressure
	50 leak tests	Pressurized to ≥ 1085 psig
	35 hydrostatic pressure tests	Pressurized to ≥ 1356 psig

Proposed TS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor Coolant System	200 heatup cycles at ≤ 100°F/h and 200 cooldown cycles at ≤ 100°F/h	Heatup cycle -Tave from ≤ 200°F to ≥550°F Cooldown cycle -Tave from ≥550°F to ≤ 200°F
	200 pressurizer cooldown cycles at ≤ 200°F/h **from nominal pressure**	Pressurizer cooldown cycle temperature from ≥ 650°F to ≤ 200°F
	200 pressurizer cooldown cycles at ≤ 200°F/h from 400 psia	**Pressurizer cooldown cycle temperature from ≥ 650°F to ≤ 200°F**
	80 loss of load cycles, without immediate Turbine or Reactor trip	≥ 15% of RATED THERMAL POWER to 0% of RATED THERMAL POWER
	40 cycles of loss-of-offsite A.C.	Loss-of-offsite A.C. electrical ESF

	electrical power	Electrical System
	80 cycles of loss of flow in one reactor coolant loop	Loss of only one reactor coolant pump
	400 reactor trip cycles	100% to 0% of RATED THERMAL POWER
	10 cycle of inadvertent auxiliary spray	**Spray water temperature differential to 560°F**
	150 **primary to secondary side** leak tests	Pressurized to ≥ 2435 psig
	15 primary to secondary side leak tests	**Pressurized to 2250 psig**
	5 hydrostatic pressure tests	Pressurized to **2485 psig and 400°F**
Secondary Coolant System	~~6 loss of secondary pressure~~	~~Loss of secondary pressure~~
	50 **hydrostatic pressure** tests	Pressurized to ≥ 1085 psig
	10 hydrostatic pressure tests	Pressurized to ≥ 1356 psig
	15 secondary to primary side leak tests	Pressurized to 840 psig

The licensee stated:

> As stated in LR Section 2.2.6, NSSS Design Transients, the transients listed in LR Table 2.2.6-1 and their associated frequencies of occurrence at EPU conditions are unchanged from those in the current design basis. Table 5.6-1 is proposed to be updated, however, to clarify that there is a separate limit for the number of pressurizer cooldown cycles from nominal pressure and from 400 psia. Transients are also proposed to be added and one to be deleted from Table 5.6-1 to make the selection of transients listed consistent with NUREG-0452.

<u>NRC Technical Evaluation</u>

The licensee stated in Section 2.2.6.2 of Attachment 4 in its application dated October 21, 2010, that the TS Table 5.6-1 values conservatively estimated the magnitude and frequency of the temperature and pressure transients resulting from various plant conditions. These magnitudes and frequencies were evaluated within the component fatigue analysis discussed within Section 2.2.2 of the staff's safety evaluation. Furthermore, the frequency of occurrence for the parameters within Table 5.6-1 are unchanged for EPU conditions.

The licensee's revisions to Table 5.6-1 are administrative in that they align the TSs to NUREG-0452, Rev 4a, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors." The values within the table remain consistent with the NSSS Design parameters contained in Turkey Point UFSAR Table 1.4-1. Thus, the licensee provides adequate assurance that Table 5.6-1 adequately covers component cyclic or transient limits. Therefore, the staff found the Table 5.6-1 changes acceptable.

Technical Specification 6.9.1.7 Core Operating Limits Report

Current TS

The analytical methods used to determine the AFD limits shall be those previously reviewed and approved by the NRC in:

1. WCAP-10216-P-A, RELAXATION OF CONSTANT AXIAL OFFSET CONTROL OF F_Q SURVEILLANCE TECHNICAL SPECIFICATION," June 1983.

The analytical methods used to determine $F_Q(Z)$, $F_{\Delta H}$ and the K(Z) curve shall be those previously reviewed and approved by the NRC in:

3. WCAP-10054-P, Addendum 2, Revision 1 (proprietary), "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection in the Broken Loop and Improved Condensation Model," October 1995.*

4. WCAP-12945-P, "Westinghouse Code Qualification Document for Best Estimate LOCA Analysis," Volumes I-V, June 1996**

Proposed TS

The analytical methods used to determine the AFD limits shall be those previously reviewed and approved by the NRC in:

1. WCAP-10216-P-A, "RELAXATION OF CONSTANT AXIAL OFFSET CONTROL OF F_Q SURVEILLANCE TECHNICAL SPECIFICATION," June 1983.

The analytical methods used to determine $F_Q(Z)$, $F_{\Delta H}$ and the K(Z) curve shall be those previously reviewed and approved by the NRC in:

3. WCAP-10054-P-A, Addendum 2, Revision 1 (proprietary), "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection in the Broken Loop and COSI Condensation Model," July 1997.

4. WCAP-16009-P-A, "Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)", January 2005

The licensee stated:

> The proposed changes incorporate updated NRC-approved methodologies.

NRC Technical Evaluation

The staff explicitly evaluated the licensee's emergency core cooling system evaluations performed in accordance with References 3 and 4, above, and found their implementation acceptable as discussed in Section 2.8.5.6.3 of this SE.

In the October 21, 2010, application, the licensee referenced WCAP-10216-P-A, "Relaxation of Constant Axial Offset Control F_Q Surveillance Technical Specification," February 1994, for determining axial flux difference limits in the TS 6.9.1.7, Core Operating Limits Report. The NRC staff requested for additional information for the proposed revision of using the February 1994 edition as opposed to the June 1983 edition. By letter dated December 22, 2011, FPL determined that the current WCAP reference dated June 1983 should not be updated to the February 1994 edition as proposed and therefore, withdrew the proposed change.

By letter dated February 21, 2011, FPL submitted a LAR to revise the Turkey Point, Units 3 and 4 TSs to relocate selected figures and values from the TSs to the Core Operating Limits Report COLR. By letter dated February 24, 2012, the NRC staff approved the license amendment and issued Amendment Nos. 247 and 243 for Turkey Point, Units 3 and 4, respectively.

By Letter dated March 15, 2012, FPL identified those COLR TS pages issued in Amendment Nos. 247 and 243 that supersede the EPU application TS pages. In addition, the licensee also stated that the EPU parameters included on these pages will be relocated to the COLR and that the values of the relocated parameters remain unchanged from the values reviewed by the NRC staff for the EPU LAR. Each COLR value submitted under the EPU LAR but which are relocated to the COLR as a result of the February 24, 2012, approval are described and evaluated in this safety evaluation. WCAP-8745-P-A, "Design Basis for the Thermal Overtemperature ΔT and Overpower ΔT Trip Functions," September 1986, was added to the list.

3.3 Additional License Conditions

The following additional license conditions will be implemented prior to operation of either unit at EPU conditions:

1. Prior to completion of the Cycle 26 refueling outage for Unit 3 and cycle 27 refueling outage for Unit 4, the licensee shall provide confirmation to the NRC staff that the design, structural integrity evaluations, and installation associated with the modifications related to the spent fuel pool supplemental heat exchangers are complete, and that the results demonstrate compliance with the appropriate FSAR and code requirements. As part of the confirmation, the licensee shall provide a summary of the structural qualification results of the piping, pipe supports, supplemental heat exchanger supports, and the inter-tie connection with the existing heat exchanger for the appropriate load.

2. PAD 4.0 TCD has been specifically approved for use for the Turkey Point licensing basis analyses. Upon NRC's approval of a revised generic version of PAD that accounts for Thermal Conductivity Degradation (TCD), FPL will within six months:

   a. Demonstrate that PAD 4.0 TCD remains conservatively bounding in licensing basis analyses when compared to the new generically approved version of PAD w/TCD, or

   b. Provide a schedule for the re-analysis using the new generically approved version of PAD w/TCD for any of the affected licensing basis analyses.

3. With respect to Technical Specification 5.5.1.3, FPL shall not credit any burnable absorber other than Integral Fuel Burnable Absorber (IFBA) for storage of fuel assemblies in the Region I spent fuel racks

a. <u>REGULATORY COMMITMENTS</u>

The following list identifies regulatory commitments made by the licensee as provided in its October 21, 2010, letter and supplements.

1. Turkey Point Nuclear Plant (PTN) will implement a modification to ensure that no single active failure can prevent hot leg or cold leg safety injection flow during the injection or recirculation mode, consistent with Turkey Point's existing design and licensing basis.

2. Upgrade main generator, including rewinding stator, new rotor, current transformers, hydrogen coolers, and exciter air cooler (applies to each unit separately).

3. Iso-phase bus duct modifications (applies to Unit 3 only; Unit 4 modification was installed during refueling outage PTN4-26).

4. Replace unit auxiliary transformers (applies to Unit 3 only; Unit 4 modification was installed during refueling outage PTN4-26).

5. Switchyard modifications (single modification applies to both units).

6. Prior to completion of the Cycle 26 refueling outage for Unit 3 and cycle 27 refueling outage for Unit 4, the licensee shall provide confirmation to the NRC staff that the design, structural integrity evaluations, and installation associated with the modifications related to the spent fuel pool supplemental heat exchangers are complete, and that the results demonstrate compliance with the appropriate FSAR and code requirements. As part of the confirmation, the licensee shall provide a summary of the structural qualification results of the piping, pipe supports, supplemental heat exchanger supports, and the inter-tie connection with the existing heat exchanger for the appropriate load.

7. PAD 4.0 TCD has been specifically approved for use for the Turkey Point licensing basis analyses. Upon NRC's approval of a revised generic version of PAD that accounts for Thermal Conductivity Degradation (TCD), FPL will within six months:

    a. Demonstrate that PAD 4.0 TCD remains conservatively bounding in licensing basis analyses when compared to the new generically approved version of PAD w/TCD, or

    b. Provide a schedule for the re-analysis using the new generically approved version of PAD w/TCD for any of the affected licensing basis analyses.

8. With respect to Technical Specification 5.5.1.3, FPL shall not credit any burnable absorber other than Integral Fuel Burnable Absorber (IFBA) for storage of fuel assemblies in the Region I spent fuel racks

9. Revise applicable procedures to support the EPU Post-LOCA cooling analyses. See Licensing Report Section 2.8.5.6.3.4, Post-LOCA Subcriticality and Long Term Cooling.

10. Revise applicable procedures to support loss of Residual Heat Removal while at reduced inventory analysis. See Licensing Report Section 2.8.7.3, Loss of Residual Heat Removal at Reduced Inventory.

11. Revise applicable procedures to implement the manual operator actions required to achieve safe shutdown for fires in each fire zone. See Licensing Report Section 2.5.1.4, Fire Protection.

12. EPU power ascension testing will be performed prior to operation of each unit at EPU conditions. See Licensing Report Sections 2.11.1, Human Factors, and 2.12.1, Power Ascension and Testing Plan.

13. Verify bounding calibration test data and confirm that actual field performance meets the uncertainty bounds established with the implementation of LEFM CheckPlus™ System and modifications to steam generator blowdown flow and main steam pressure instrumentation (per Item 2 in Table 2.12-5 of Attachment 4 to the LAR).

5.0 RECOMMENDED AREAS FOR INSPECTION

As described above, the Nuclear Regulatory Commission (NRC) staff has conducted an extensive review of the licensee's plans and analyses related to the proposed extended power uprate (EPU) and concluded that they are acceptable. The NRC staff's review has identified the following areas for consideration by the NRC inspection staff during the licensee's implementation of the proposed EPU. These areas are recommended based on past experience with EPUs, the extent and unique nature of modifications necessary to implement the proposed EPU, and new conditions of operation necessary for the proposed EPU. They do not constitute inspection requirements, but are intended to give inspectors insight into important bases for approving the EPU.

- Power ascension testing activities

- At the end of the first quarter (92 days) of power operations following implementation of the EPU, it is recommended that the NRC Region II Office perform a follow-up inspection to verify that this normalization procedure provided results that were consistent with or conservative with respect to the anticipated RTD drift and deviations in ΔT_o, T' or T"

In addition to the recommended areas for inspection listed above, NRC Inspection Procedure 71004, "Power Uprates," provides guidance for conducting inspections associated with power uprate amendments including considerations for selecting inspection samples.

6.0 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, U.S. Nuclear Regulatory Commission, the State of Florida does not desire notification of issuance of license amendments.

7.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, “Criteria for and Identification of Licensing and Regulatory Actions Requiring Environmental Assessments”; 10 CFR 51.32, “Finding of No Significant Impact”; 10 CFR 51.33, “Draft Finding of No Significant Impact; Distribution”; and 10 CFR 51.35, “Requirement to Publish Finding of No Significant Impact; Limitation on Commission Action,” the NRC staff prepared a draft environmental assessment and draft finding of no significant impact, published in the *Federal Register* on November 17, 2011 (76 FR 71379). The draft Environmental Assessment provided a 30-day opportunity for public comment. The NRC staff received comments that were addressed in the final environmental assessment. The final environmental assessment was published in the *Federal Register* on April 3, 2012 (77 FR 20059). Accordingly, based upon the environmental assessment, the Commission has determined that the issuance of this amendment will not have a significant effect on the quality of the human environment.

8.0 CONCLUSION

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

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Date: June 15, 2012

LIST OF ACRONYMS

Aac	alternate alternating current
AB	auxiliary building
ac	alternating current
ADAMS	Agencywide Documents Access and Management System
ADV	atmospheric dump valves
AEC	Atomic Energy Commission
AFT	as-found tolerance band
AFW	Auxiliary Feedwater
AIF	Atomic Industrial Forum
AISC	American Institute of Steel Construction
AL	analytical limit
ALARA	as low as is reasonably achievable
ALT	as-left tolerance band
ANSI	American National Standards Institute
AOR	analysis of record
AOT	allowed outage time
AOV	air-operated valve
ARL	Alden Research Laboratories
ART	adjusted reference temperature
ASA	American Standards Association
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transients without scram
AV	allowable value
B&PV Code	ASME *Boiler and Pressure Vessel Code*
BHP	brake horsepower
BMI	bottom mounted instrumentation
BOP	balance-of-plant
BTP	branch technical position
CASS	cast austenitic stainless steel
CCW	component cooling water
CDF	core damage frequency
CFs	chemistry factors
CFS	condensate and feedwater system
CHF	critical heat flux
CLB	current licensing basis
CMTR	certified material test reports

COT	channel operation test
CPU	central processing unit
CR	control room
CRDMC	control rod drive mechanism cooling
CREVS	control room emergency ventilation system
CSA	channel statistical allowance
CSS	core support structures
CST	condensate storage tanks
CUF	cumulative usage factor
CWS	circulating water system
DBLOCA	design basis loss-of-coolant accident
dc	direct current
DCS	distributed control system
DEHC	digital electro-hydraulic control
DFBN	debris filter bottom nozzle
DNB	departure from nucleate boiling
DRFA	debris resistant fuel assembly
DWST	demineralized water storage tank
EAB	exclusion area boundary
ECCSs	emergency core cooling systems
EDG	emergency diesel generator
EER	electrical equipment room
EFDS	equipment and floor drainage system
EFPY	effective full-power years
EHC	electro-hydraulic control
EMA	equivalent margin analysis
EOL	end-of-life
EOP	emergency operating procedures
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
F&Os	facts and observations
FAC	Flow accelerated corrosion
FCV	feedwater control valve
FEA	finite element analysis
FIVs	feedwater isolation valves
FPL	Florida Power & Light Company

FSAR	Final Safety Analysis Report
GALL Report	Generic Aging Lessons Learned Report (NUREG -1801)
GDC	general design criterion/criteria
GL	generic letter
GWMS	gaseous waste management systems
HELB	high energy line break
HEP	human error probabilities
HHSI	high head safety injection
HP	high-pressure
HRA	Human Reliability Analysis
I&C	instrumentation and control
IASCC	irradiation-assisted stress corrosion cracking
ICW	intake cooling water
IE	irradiation embrittlement
IEEE	Institute of Electrical and Electronics Engineers
IFM	intermediate flow mixing
IGSCC	Intergranular stress corrosion cracking
IPBD	isolated phase bus duct
IPE	individual plant examination
IPEEE	individual plant examinations of external events
IS	intermediate shell
IST	inservice test
ITDP	improved thermal design procedure
LAR	license amendment equest
LBB	leak before break
LCO	limiting condition for operation
LEFM	leading edge flow meter
LERF	large early release frequency
LMFW	loss of main feedwater
LOCA	loss-of-coolant accident
LOL/TT	loss-of-electrical-load/turbine-trip
LOOP	loss of offsite power
LPZ	low population zone
LR	Licensing Report
LS	lower shell
LSSS	limiting safety system setting
LTOP	low temperature overpressure protection
LTSP	limiting trip setpoint
LWMS	liquid waste management system

LWR	light water reactor
M&E	mass and energy
MAAP	modular accident analysis program
MCES	main condenser evacuation system
MCO	moisture carryover
MCO	moisture carryover
MFCVs	main feedwater control valves
MFIVs	modification of existing feedwater isolation valves
MFW	main feedwater
MPE	maximum potential earthquake
MSCV	main steam check valve
MSIV	main steam isolation valve
MT	main transformer
MUR	measurement uncertainty recapture
NCC	normal containment cooling
NPSH	net positive suction head
NPSHA	net positive suction head available
NPSHR	net positive suction head required
NR	narrow range
NRC	Nuclear Regulatory Commission
NSSS	nuclear steam supply system
NTS	nominal trip setpoint
NTSP	nominal trip setpoint
NUMARC	Nuclear Utility Management and Resource Council
NUREG-0800	Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [Light Water Reactor] Edition (SRP)
OBE	operating basis earthquake
ODSCC	outside diameter stress-corrosion cracking
OLTP	original licensed thermal power
OM Code	ASME *Code for Operation and Maintenance of Nuclear Power Plants*
OMS	overpressure mitigation system
OOS	out of service
OTC	once through cooling
PAOT	post accident operability time
PASS	post accident sampling system
PATP	power ascension and testing plan
PRA	probabilistic risk assessment
PRT	pressurizer relief tank
PSS	power system stabilizer

P-T	pressure-temperature
PTN	Turkey Point Nuclear Plant
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
RAI	request for additional information
RCA	rack calibration accuracy
RCL	reactor coolant loop
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RG	regulatory guide
RHR	residual heat removal
RIS	regulatory issue summary
RPV	reactor pressure vessel
RS	review standard
RTDP	revised thermal design procedure
RTDs	resistance temperature detectors
RV	reactor vessel
RVCH	reactor vessel closure heads
RVI	reactor internals and core supports
RVID	Reactor Vessel Integrity Database
RWST	refueling water storage tank
SAFDLs	specified acceptable fuel design limits
SAL	safety analysis limit
SCC	stress corrosion cracking
SE	safety evaluation
SER	safety evaluation report
SFP	spent fuel pit
SFPCCS	spent fuel pool cooling and cleanup system
SG	steam generator
SGBS	SG blowdown system
SGTR	steam generator tube rupture
SI	Safety Injection
SPDS	safety parameter display system
SPU	stretch power uprate
SR	stress relaxation
SRP	Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [Light Water Reactor] Edition (NUREG-0800)
SRSS	square-root-sum-of-squares

SRXB	Reactor Systems Branch
SSCs	structures, systems, and components
SSE	safe shutdown earthquake
SSGFPs	standby steam generator feed pumps
STDP	standard thermal design procedure
STS	standard technical specifications
SWS	service water system
TA	total allowance
TBS	turbine bypass system
TCS	turbine control system
TEDE	total effective dose equivalent
TG	turbine generator
TGSCC	transgranular stress corrosion cracking
TGSS	turbine gland sealing system
TLU	total loop uncertainty
TPCW	turbine plant cooling water
TS	technical specification
TSC	technical support center
TSTF	Technical Specification Task Force
UCP	upper core plate
UFMs	ultrasonic flow meters
UFSAR	Updated Final Safety Analysis Report
US	upper shell
USC	upper support column
USE	upper shelf energy
USI	unresolved safety issue
UT	ultrasonic techniques
WCAP	Westinghouse commercial atomic power
WOG	Westinghouse Owners Group

The NRC has determined that the related safety evaluation (SE) contains proprietary information pursuant to Title 10 of the *Code of Federal Regulations,* Section 2.390, "Public Inspections, Exemptions, Requests for Withholding." Accordingly, the NRC staff has also prepared a redacted, publicly-available, non-proprietary version of the SE. Copies of the proprietary and non-proprietary versions of the SE are enclosed.

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

Sincerely,
/RA/
Jason C. Paige, Project Manager
Plant Licensing Branch II-2
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-250 and 50-251

Enclosures:
1. Amendment No. 249 to DPR-31
2. Amendment No. 245 to DPR-41
3. Non-Proprietary Safety Evaluation
4. Proprietary Safety Evaluation (ML11293A366)

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* Via memo **Via email

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