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

July 18, 2012

Vice President, Operations
Entergy Operations, Inc.
Grand Gulf Nuclear Station
P.O. Box 756
Port Gibson, MS 39150

SUBJECT: GRAND GULF NUCLEAR STATION, UNIT 1 - ISSUANCE OF AMENDMENT RE: EXTENDED POWER UPRATE (TAC NO. ME4679)

Dear Sir or Madam:

The U.S. Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 191 to Facility Operating License No. NPF-29 for the Grand Gulf Nuclear Station, Unit 1 (GGNS). This amendment consists of changes to the Technical Specifications (TSs) in response to your application dated September 8, 2010, as supplemented by letters dated November 18, 2010, November 23, 2010, February 23, 2011 (four letters), March 9, 2011 (two letters), March 22, 2011, March 30, 2011, March 31, 2011, April 14, 2011, April 21, 2011, May 3, 2011, May 5, 2011, May 11, 2011, June 8, 2011, June 15, 2011, June 21, 2011, June 23, 2011, July 6, 2011, July 28, 2011, August 25, 2011, August 29, 2011, August 30, 2011, September 2, 2011, September 9, 2011, September 12, 2011, September 15, 2011, September 26, 2011, October 10, 2011, October 24, 2011, November 14, 2011, November 25, 2011, November 28, 2011, December 19, 2011, February 6, 2012, February 15, 2012, February 20, 2012, March 13, 2012, March 21, 2012, April 5, 2012, April 18, 2012 (two letters), April 26, 2012, May 9, 2012, and June 12, 2012. Portions of the letters dated September 8 and November 23, 2010, and February 23, April 21, May 11, July 6, July 28, September 2, October 10, November 14, November 25, and November 28, 2011, and February 6, February 15, February 20, March 13, March 21, April 5, April 18, and May 9, 2012, contain sensitive unclassified non-safeguards information (proprietary) and, accordingly, have been withheld from public disclosure.

The amendment increases the maximum steady-state reactor core power level from 3,898 megawatts thermal (MWt) to 4,408 MWt, which is an increase of approximately 15 percent from the original licensed thermal power level of 3,833 MWt. The proposed increase in power level is considered an extended power uprate.

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 non-proprietary version of the SE, which is provided in Enclosure 2. The proprietary

NOTICE: Enclosure 3 to this letter contains Proprietary Information. Upon separation from Enclosure 3, this letter is DECONTROLLED.

version of the SE is provided in Enclosure 3. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

Alan Wang

Alan B. Wang, Project Manager
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-416

Enclosures:
1. Amendment No. 191 to NPF-29
2. Safety Evaluation (non-proprietary)
3. Safety Evaluation (proprietary)

cc: Listserv w/o enclosure 3

ENCLOSURE 1

AMENDMENT NO. 191

TO FACILITY OPERATING LICENSE NO. NPF-29

ENTERGY OPERATIONS, INC.

GRAND GULF NUCLEAR STATION, UNIT 1

DOCKET NO. 50-416

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

ENTERGY OPERATIONS, INC.

SYSTEM ENERGY RESOURCES, INC.

SOUTH MISSISSIPPI ELECTRIC POWER ASSOCIATION

ENTERGY MISSISSIPPI, INC.

DOCKET NO. 50-416

GRAND GULF NUCLEAR STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 191
License No. NPF-29

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

   A. The application for amendment by Entergy Operations, Inc. (the licensee), dated September 8, 2010, as supplemented by letters dated November 18, 2010, November 23, 2010, February 23, 2011 (four letters), March 9, 2011 (two letters), March 22, 2011, March 30, 2011, March 31, 2011, April 14, 2011, April 21, 2011, May 3, 2011, May 5, 2011, May 11, 2011, June 8, 2011, June 15, 2011, June 21, 2011, June 23, 2011, July 6, 2011, July 28, 2011, August 25, 2011, August 29, 2011, August 30, 2011, September 2, 2011, September 9, 2011, September 12, 2011, September 15, 2011, September 26, 2011, October 10, 2011, October 24, 2011, November 14, 2011, November 25, 2011, November 28, 2011, December 19, 2011, February 6, 2012, February 15, 2012, February 20, 2012, March 13, 2012, March 21, 2012, April 5, 2012, April 18, 2012 (two letters), April 26, 2012, May 9, 2012, and June 12, 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 Technical Specifications as indicated in the attachment to this license amendment, and paragraphs 2.C.(1) and 2.C.(2) of Facility Operating License No. NPF-29 are hereby amended to read as follows:

(1) Maximum Power Level

Entergy Operations, Inc. is authorized to operate the facility at reactor core power levels not in excess of 4408 megawatts thermal (100 percent power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 191 are hereby incorporated into this license. Entergy Operations, Inc. shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

During Cycle 19, GGNS will conduct monitoring of the Oscillation Power Range Monitor (OPRM). During this time, the OPRM Upscale function (Function 2.f of Technical Specification Table 3.3.1.1-1) will be disabled and operated in an "indicate only" mode and technical specification requirements will not apply to this function. During such time, Backup Stability Protection measures will be implemented via GGNS procedures to provide an alternate method to detect and suppress reactor core thermal hydraulic instability oscillations. Once monitoring has been successfully completed, the OPRM Upscale function will be enabled and technical specification requirements will be applied to the function; no further operating with this function in an "indicate only" mode will be conducted.

3. In addition, the license is amended by the addition of three license conditions, as indicated in the attachment to this amendment. Accordingly, new paragraphs 2.C.(44), 2.C.(45), and 2.C.(46), of Facility Operating License No. NPF-29 will read as follows:

(44) Leak rate tests associated with Surveillance Requirements (SR) 3.6.1.1.1, 3.6.1.3.5, and 3.6.1.3.9, as required by TS 5.5.12 and in

accordance with 10 CFR 50, Appendix J, Option B, and SRs 3.6.5.1.1 and 3.6.5.1.2 are not required to be performed until their next scheduled performance dates. The tests will be performed at the EPU calculated peak containment pressure or within EPU drywell bypass leakage limits, as appropriate.

(45) Through Cycle 19 or until the revised criticality safety analysis has been approved, whichever comes first, the storage cells in the GGNS SFP racks shall be categorized as either Unrestricted or Restricted.

(a) Unrestricted cells (Region I) are cells with a minimum panel B10 areal density greater than 0.0179 gm/cm^2 and that have received an exposure less than 2.3E10 rads. Unrestricted cells may contain fuel assemblies up to the maximum k-infinity of 1.26 (cold core configuration).

(b) Restricted cells (Region II) are cells with either a minimum panel B10 areal density less than 0.0179 gm/cm^2 or that have received an exposure in excess of 2.3E10 rads. Storage in Restricted cells shall not credit any Boraflex. Storage shall be controlled in a 10 of 16 configuration (see below). In addition, only fuel assemblies with a k-infinity of less than 1.21 (cold core configuration) may be stored in a Region II cell.

Region II 4X4 Storage Configuration

	B		B
B			
	B		B
		B	

	Fuel Assembly Storage Location
B	Location Physically Blocked to Prevent Storage

(46) This license condition provides for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant structures, systems, and components (including verifying the continued structural integrity of the steam dryer) for power ascension from the CLTP (3898 MWt) to the EPU level of 4408 MWt (or 113 percent of CLTP or 115 percent of OLTP).

(a) The following requirements are placed on operation of the facility before and during the power ascension to 3898 MWt:

1. GGNS shall provide a Power Ascension Test (PAT) Plan for the Steam Dryer testing. This plan shall include:

   - Criteria for comparison and evaluation of projected strain and acceleration with on-dryer instrument data.

   - Acceptance limits developed for each on-dryer strain gauge and accelerometer.

   - Tables of predicted dryer stresses at CLTP, strain amplitudes and PSDs at strain gauge locations, acceleration amplitudes and PSDs at accelerometer locations, and maximum stresses and locations.

   The PAT plan shall provide correlations between measured accelerations and strains and the corresponding maximum stresses. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up.

2. GGNS shall monitor the main steam line (MSL) strain gages and on-dryer instrumentation at a minimum of three power levels up to 3898 MWt. Based on a comparison of projected and measured strains and accelerations, GGNS will assess whether the dryer acoustic and structural models have adequately captured the response significant to peak stress projections. If the measured strains and accelerations are not within the CLTP acceptance limits, the new measured data will be used to re-perform the full structural re-analysis for the purposes of generating modified EPU acceptance limits.

3. GGNS shall provide a summary of the data and evaluation of predicted and measured pressures, strains, and accelerations. This data will include the GGNS-specific bias and uncertainty data and transfer function, revised peak stress table and any revised acceptance limits. The predicted pressures

shall include those using both PBLE methods (that is, Method 1 using on-dryer data, and Method 2 using MSL data). It shall be provided to the NRC Project Manager upon completion of the evaluation. GGNS shall not increase power above 3898 MWt until the NRC PM notifies GGNS the NRC accepts the evaluation or NRC questions regarding the evaluation have been addressed. If no questions are identified within 240 hours after the NRC receives the evaluation, power ascension may continue.

(b) The following requirements are placed on operation of the facility during the initial power ascension from 3898 MWt to the approved EPU level (4408 MWt):

1. GGNS shall increase power in increments of approximately 102 MWt, hold the facility at approximately steady state conditions and collect data from available main steam line (MSL) strain gages and available on-dryer instrumentation. This data will be evaluated, including the comparison of measured dryer strains and accelerations to acceptance limits and the comparison of predicted dryer loads based on MSL strain gage data to acceptance limits. It will also be used to trend and project loads at the next test point and to EPU conditions to demonstrate margin for continued power ascension.

2. Following the data collection and evaluation at the plateaus at approximately 4102 MWt, 4306 MWt, and 4408 MWt, GGNS shall provide a summary of the data and the evaluation performed in Section b.1 above to the NRC Project Manager. GGNS shall not increase power above these power levels for up to 96 hours to allow for NRC review of the information.

3. Should the measured strains and accelerations on the dryer exceed the level 1 acceptance limits, or alternatively if the dryer instrumentation is not available and the projected load on the dryer from the MSL strain gage data exceeds the Level 1 acceptance limits, GGNS shall return the facility to a power level at which the limits are not exceeded. GGNS shall resolve the discrepancy, evaluate and

document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. GGNS shall not increase power for up to 96 hours to allow for NRC review of the information.

a. In the event that acoustic signals (in MSL strain gage signals) are identified that challenge the dryer acceptance limits during power ascension above 3898 MWt, GGNS shall evaluate dryer loads, and stresses, including the effect of ±10 percent frequency shift, and re-establish the acceptance limits and determine whether there is margin for continued power ascension.

b. During power ascension above 3898 MWt, if an engineering evaluation for the steam dryer is required because a Level 1 acceptance limit is exceeded, GGNS shall perform the structural analysis using the Steam Dryer Report, Appendix A methods to address frequency uncertainties up to ±10% and assure that peak responses that fall within this uncertainty band are addressed.

4. Following the data collection and evaluation at the EPU power level, GGNS shall provide a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the GGNS-specific bias and uncertainties and transfer function. The GGNS-specific bias and uncertainties summary shall include both PBLE Method 1 and Method 2. This report shall be transmitted to the NRC within 90 days of achieving the EPU power level. Should the results of this stress analysis indicate the allowable stress in any part of the dryer is exceeded, GGNS shall reduce power to a level at which the allowable stress is met, evaluate the dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of dryer integrity at EPU conditions,

shall be provided to the NRC prior to return to EPU conditions.

(c) Entergy shall implement the following actions:

1. Entergy shall revise the post-EPU monitoring and inspection program to reflect long-term monitoring of plant parameters potentially indicative of steam dryer failure; to reflect consistency of the facility's steam dryer inspection program with GE SIL 644, "BWR Steam Dryer Failure," Revision 2; and with BWRVIP-139, "Steam Dryer Inspection and Flaw Evaluation Guidelines."

(d) Entergy shall prepare the EPU PAT plan to include the following and provide it to the NRC project manager before increasing power above 3898 MWt:

1. Level 1 and Level 2 acceptance limits for on-dryer strain gages, on-dryer accelerometers, and for projected dryer loads from MSL strain gage data to be used up to 113 percent of CLTP

2. specific hold points and their duration during EPU power ascension

3. activities to be accomplished during hold points

4. plant parameters to be monitored

5. inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points

6. methods to be used to trend plant parameters

7. acceptance criteria for monitoring and trending plant parameters and conducting the walkdowns and inspections

8. actions to be taken if acceptance criteria are not satisfied

9. verification of the completion of commitments and planned actions specified in the Entergy application and all supplements to the application in support of

the EPU LAR pertaining to the steam dryer before power increase above 3898 MWt

10. identify the NRC PM as the NRC point of contact for providing PAT plan information during power ascension

11. methodology for updating limit curves

(e) The key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval. Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(f) During the first two scheduled refueling outages after reaching full EPU conditions, Entergy shall conduct a visual inspection of all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 and GE inspection guidelines. Entergy shall report the results of the visual inspections of the steam dryer to the NRC staff within 60 days following startup.

(g) At the end of the second refueling outage, following the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results for NRC review and approval.

(h) This license condition shall expire upon satisfaction of the requirements in paragraph (f) provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw or unacceptable flaw growth that is caused by fatigue.

4. This license amendment is effective as of its date of issuance and shall be implemented within 120 days from the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Bruce A. Boger

Eric J. Leeds, Director /for/
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Facility Operating License No. NPF-29 and the Technical Specifications

Date of Issuance: July 18, 2012

ATTACHMENT TO LICENSE AMENDMENT NO. 191

FACILITY OPERATING LICENSE NO. NPF-29

DOCKET NO. 50-416

Replace the following pages of the Facility Operating License No. NPF-29 and the Appendix A, Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Facility Operating License

Remove	Insert
4	4
16a	16a
--	16b
--	16c
--	16c
--	16d
--	16e
--	16f

Technical Specifications

Remove	Insert	Remove	Insert
1.0-5	1.0-5	3.3-54	3.3-54
2.0-1	2.0-1	3.4-9	3.4-9
3.2-1	3.2-1	3.4-10	3.4-10
3.2-2	3.2-2	3.4-26	3.4-26
3.2-3	3.2-3	3.4-27	3.4-27
3.3-2	3.3-2	3.4-28	3.4-28
3.3-2a	3.3-2a	3.4-29	3.4-29
3.3-3	3.3-3	3.4-30	3.4-30
3.3-5	3.3-5	3.4-31	--
3.3-5b	3.3-5b	3.4-32	--
3.3-6	3.3-6	3.4-33	--
3.3-6a	3.3-61	3.4-34	--
3.3-7	3.3-7	3.4-35	--
3.3-8	3.3-8	--	3.7-15
3.3-25	3.3-25	5.0-16	5.0-16
3.3-26	3.3-26	--	5.0-21a
3.3-27	3.3-27		

(b) SERI is required to notify the NRC in writing prior to any change in (i) the terms or conditions of any new or existing sale or lease agreements executed as part of the above authorized financial transactions, (ii) the GGNS Unit 1 operating agreement, (iii) the existing property insurance coverage for GGNS Unit 1 that would materially alter the representations and conditions set forth in the Staff's Safety Evaluation Report dated December 19, 1988 attached to Amendment No. 54. In addition, SERI is required to notify the NRC of any action by a lessor or other successor in interest to SERI that may have an effect on the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10CFR Chapter I 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 or incorporated below:

(1) Maximum Power Level

Entergy Operations, Inc. is authorized to operate the facility at reactor core power levels not in excess of 4408 megawatts thermal (100 percent power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 191 are hereby incorporated into this license. Entergy Operations, Inc. shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

During Cycle 19, GGNS will conduct monitoring of the Oscillation Power Range Monitor (OPRM). During this time, the OPRM Upscale function (Function 2.f of Technical Specification Table 3.3.1.1-1) will be disabled and operated in an "indicate only" mode and technical specification requirements will not apply to this function. During such time, Backup Stability Protection measures will be implemented via GGNS procedures to provide an alternate method to detect and suppress reactor core thermal hydraulic instability oscillations. Once monitoring has been successfully completed, the OPRM Upscale function will be enabled and technical specification requirements will be applied to the function; no further operating with this function in an "indicate only" mode will be conducted.

(b) The first performance of the periodic assessment of CRE habitability, Specification 5.5.13.c.(ii), shall be within 3 years, plus the 9-month allowance of SR 3.0.2, as measured from March 2005, the date of the most recent successful tracer gas test, as stated in the June 30, 2005 letter response to Generic Letter 2003-01, or within the next 9 months if the time period since the most recent successful tracer gas test is greater than 3 years.

(c) The first performance of the periodic assessment of the CRE boundary, Specification 5.5.13.d, shall be within the next 18 months, plus the 136 days allowed by SR 3.0.2, as measured from the date of issuance of this amendment.

(44) Leak rate tests associated with Surveillance Requirements (SR) 3.6.1.1.1, 3.6.1.3.5, and 3.6.1.3.9, as required by TS 5.5.12 and in accordance with 10 CFR 50, Appendix J, Option B, and SRs 3.6.5.1.1 and 3.6.5.1.2 are not required to be performed until their next scheduled performance dates. The tests will be performed at the EPU calculated peak containment pressure or within EPU drywell bypass leakage limits, as appropriate.

(45) Through Cycle 19 or until the revised criticality safety analysis has been approved, whichever comes first, the storage cells in the GGNS SFP racks shall be categorized as either Unrestricted or Restricted.

(a) Unrestricted cells (Region I) are cells with a minimum panel B10 areal density greater than 0.0179 gm/cm^2 and that have received an exposure less than 2.3E10 rads. Unrestricted cells may contain fuel assemblies up to the maximum k-infinity of 1.26 (cold core configuration).

(b) Restricted cells (Region II) are cells with either a minimum panel B10 areal density less than 0.0179 gm/cm^2 or that have received an exposure in excess of 2.3E10 rads. Storage in Restricted cells shall not credit any Boraflex. Storage shall be controlled in a 10-of-16 configuration (see below). In addition, only fuel assemblies with a k-infinity of less than 1.21 (cold core configuration) may be stored in a Region II cell.

Region II 4X4 Storage Configuration

	B		B
B			
	B		B
		B	

	Fuel Assembly Storage Location
B	Location Physically Blocked to Prevent Storage

(46) This license condition provides for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant structures, systems, and components (including verifying the continued structural integrity of the steam dryer) for power ascension from the CLTP (3898 MWt) to the EPU level of 4408 MWt (or 113 percent of CLTP or 115 percent of OLTP).

(a) The following requirements are placed on operation of the facility before and during the power ascension to 3898 MWt:

1. GGNS shall provide a Power Ascension Test (PAT) Plan for the Steam Dryer testing. This plan shall include:

   - Criteria for comparison and evaluation of projected strain and acceleration with on-dryer instrument data.

   - Acceptance limits developed for each on-dryer strain gauge and accelerometer.

   - Tables of predicted dryer stresses at CLTP, strain amplitudes and PSDs at strain gauge locations, acceleration amplitudes and PSDs at accelerometer locations, and maximum stresses and locations.

   The PAT plan shall provide correlations between measured accelerations and strains and the corresponding maximum stresses. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up.

2. GGNS shall monitor the main steam line (MSL) strain gages and on-dryer instrumentation at a minimum of three power levels up to 3898 MWt. Based on a comparison of projected and measured strains and accelerations, GGNS will assess whether the dryer acoustic and structural models have adequately captured the response significant to peak stress projections.

If the measured strains and accelerations are not within the CLTP acceptance limits, the new measured data will be used to re-perform the full structural re-analysis for the purposes of generating modified EPU acceptance limits.

3. GGNS shall provide a summary of the data and evaluation of predicted and measured pressures, strains, and accelerations. This data will include the GGNS-specific bias and uncertainty data and transfer function, revised peak stress table and any revised acceptance limits. The predicted pressures shall include those using both PBLE methods (that is, Method 1 using on-dryer data, and Method 2 using MSL data). It shall be provided to the NRC Project Manager upon completion of the evaluation. GGNS shall not increase power above 3898 MWt until the NRC PM notifies GGNS the NRC accepts the evaluation or NRC questions regarding the evaluation have been addressed. If no questions are identified within 240 hours after the NRC receives the evaluation, power ascension may continue.

(b) The following requirements are placed on operation of the facility during the initial power ascension from 3898 MWt to the approved EPU level (4408 MWt):

1. GGNS shall increase power in increments of approximately 102 MWt, hold the facility at approximately steady state conditions and collect data from available main steam line (MSL) strain gages and available on-dryer instrumentation. This data will be evaluated, including the comparison of measured dryer strains and accelerations to acceptance limits and the comparison of predicted dryer loads based on MSL strain gage data to acceptance limits. It will also be used to trend and project loads at the next test point and to EPU conditions to demonstrate margin for continued power ascension.

2. Following the data collection and evaluation at the plateaus at approximately 4102 MWt, 4306 MWt, and 4408 MWt, GGNS shall provide a summary of the data and the evaluation performed in Section b.1 above to the NRC Project Manager. GGNS shall not increase power above these power levels for up to 96 hours to allow for NRC review of the information.

3. Should the measured strains and accelerations on the dryer exceed the level 1 acceptance limits, or alternatively if the dryer instrumentation is not available and the projected load on the dryer from the MSL strain gage data exceeds the Level 1 acceptance limits, GGNS shall return the facility to a power level at which the limits are not exceeded. GGNS shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager

prior to further increases in reactor power. GGNS shall not increase power for up to 96 hours to allow for NRC review of the information.

a. In the event that acoustic signals (in MSL strain gage signals) are identified that challenge the dryer acceptance limits during power ascension above 3898 MWt, GGNS shall evaluate dryer loads, and stresses, including the effect of ± 10% frequency shift, and re-establish the acceptance limits and determine whether there is margin for continued power ascension.

b. During power ascension above 3898 MWt, if an engineering evaluation for the steam dryer is required because a Level 1 acceptance limit is exceeded, GGNS shall perform the structural analysis using the Steam Dryer Analysis Report, Appendix A methods to address frequency uncertainties up to ± 10% and assure that peak responses that fall within this uncertainty band are addressed.

4. Following the data collection and evaluation at the EPU power level, GGNS shall provide a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the GGNS-specific bias and uncertainties and transfer function. The GGNS-specific bias and uncertainties summary shall include both PBLE Method 1 and Method 2. This report shall be transmitted to the NRC within 90 days of achieving the EPU power level. Should the results of this stress analysis indicate the allowable stress in any part of the dryer is exceeded, GGNS shall reduce power to a level at which the allowable stress is met, evaluate the dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of dryer integrity at EPU conditions, shall be provided to the NRC prior to return to EPU conditions.

(c) Entergy shall implement the following actions:

1. Entergy shall revise the post-EPU monitoring and inspection program to reflect long-term monitoring of plant parameters potentially indicative of steam dryer failure; to reflect consistency of the facility's steam dryer inspection program with GE SIL 644, "BWR Steam Dryer Failure," Revision 2; and with BWRVIP-139, "Steam Dryer Inspection and Flaw Evaluation Guidelines."

(d) Entergy shall prepare the EPU PATP to include the following and provide it to the NRC project manager before increasing power above 3898 MWt:

1. Level 1 and Level 2 acceptance limits for on-dryer strain gages, on-dryer accelerometers, and for projected dryer loads from MSL strain gauge data, to be used up to 113 percent of CLTP.

2. specific hold points and their duration during EPU power ascension

3. activities to be accomplished during hold points

4. plant parameters to be monitored

5. inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points

6. methods to be used to trend plant parameters

7. acceptance criteria for monitoring and trending plant parameters and conducting the walkdowns and inspections

8. actions to be taken if acceptance criteria are not satisfied

9. verification of the completion of commitments and planned actions specified in the Entergy application and all supplements to the application in support of the EPU LAR pertaining to the steam dryer before power increase above 3898 MWt

10. identify the NRC PM as the NRC point of contact for providing PAT plan information during power ascension

11. methodology for updating limit curves

(e) The key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval. Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, ""Guidelines for Managing NRC Commitments," issued July 1999.

(f) During the first two scheduled refueling outages after reaching full EPU conditions, Entergy shall conduct a visual inspection of all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 and GE inspection guidelines. Entergy shall report the results of the visual inspections of the steam dryer to the NRC staff within 60 days following startup.

(g) At the end of the second refueling outage following the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results for NRC review and approval.

(h) This license condition shall expire upon satisfaction of the requirements in paragraph (f) provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw or unacceptable flaw growth that is caused by fatigue.

D. The facility required exemptions from certain requirements of Appendices A and J to 10 CFR Part 50 and from certain requirements of 10 CFR Part 100. These include: (a) exemption from General Design Criterion 17 of Appendix A until startup following the first refueling outage, for (1) the emergency override of the test mode for the Division 3 diesel engine, (2) the second level undervoltage protection for the Division 3 diesel engine, and (3) the generator ground over current trip function for the Division 1 and 2 diesel generators (Section 8.3.1 of SSER #7) and (b) exemption from the requirements of Paragraph III.D.2(b)(ii) of Appendix J for the containment airlock testing following normal door opening when containment integrity is not required (Section 6.2.6 of SSER #7). These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. In addition, by exemption dated December 20, 1986, the Commission exempted licensees from 10 CFR 100.11(a)(1), insofar as it incorporates the definition of exclusion area in 10 CFR 100.3(a), until April 30, 1987 regarding demonstration of authority to control all activities within the exclusion area (safety evaluation accompanying Amendment No. 27 to License (NPF-29). This exemption is authorized by law, and will not present an undue risk to the public health and safety, and is consistent with the common defense and security. In addition, special circumstances have been found justifying the exemption. Therefore, these exemptions are hereby granted pursuant to 10 CFR 50.12. with the granting of these exemptions, the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act and the rules and regulations of the Commission.

E. The licensee shall fully implement and maintain in effect all provision of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "Physical Security, Safeguards Contingency and Training and Qualification Plan," and were submitted to the NRC on May 18, 2006.

The licensee shall fully implement and maintain in effect all provisions of the Commission-approved cyber security plan (CSP), including changes made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The licensee's CSP was approved by License Amendment No. 186.

1.1 Definitions

LOGIC SYSTEM FUNCTIONAL TEST (continued)	be performed by means of any series of sequential, overlapping, or total system steps so that the entire logic system is tested.
MINIMUM CRITICAL POWER RATIO (MCPR)	The MCPR shall be the smallest critical power ratio (CPR) that exists in the core for each class of fuel. The CPR is that power in the assembly that is calculated by application of the appropriate correlation(s) to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.
MODE	A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE—OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PRESSURE TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit-specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 4408 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.

(continued)

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 With the reactor steam dome pressure < 685 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ 21.8% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ 685 psig and core flow ≥ 10% rated core flow:

MCPR shall be ≥ 1.11 for two recirculation loop operation or ≥ 1.14 for single recirculation loop operation.

2.1.1.3 Reactor vessel water level shall be greater than the top of active irradiated fuel.

2.1.2 Reactor Coolant System Pressure SL

Reactor steam dome pressure shall be ≤ 1325 psig.

2.2 SL Violations

With any SL violation, the following actions shall be completed within 2 hours:

2.2.1 Restore compliance with all SLs; and

2.2.2 Insert all insertable control rods.

(continued)

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Average Planar Linear Heat Generation Rate (APLHGR)

LCO 3.2.1 All APLHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 21.8% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any APLHGR not within limits.	A.1 Restore APLHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 21.8% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.1.1 Verify all APLHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 21.8% RTP <u>AND</u> 24 hours thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.2 Minimum Critical Power Ratio (MCPR)

LCO 3.2.2 All MCPRs shall be greater than or equal to the MCPR operating limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 21.8% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits	A.1 Restore MCPR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 21.8% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 21.8% RTP <u>AND</u> 24 hours thereafter
SR 3.2.2.2	Determine the MCPR limits.	Once within 72 hours after each completion of SR 3.1.4.1 Once within 72 hours after each completion of SR 3.1.4.2 Once within 72 hours after each completion of SR 3.1.4.4

3.2 POWER DISTRIBUTION LIMITS

3.2.3 Linear Heat Generation Rate (LHGR)

LCO 3.2.3 All LHGRs shall be less than or equal to the limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 21.8% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any LHGR not within limits	A.1 Restore LHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 21.8% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.3.1 Verify all LHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 21.8% RTP AND 24 hours thereafter

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1 Reduce THERMAL POWER to < 35.4% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1 Reduce THERMAL POWER to < 21.8% RTP.	4 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1 Be in MODE 2.	6 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1 Be in MODE 3.	12 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
J. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	J.1	Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	12 hours
	<u>AND</u>		
	J. 2	------ NOTE --------- LCO 3.0.4 is not applicable. --------------------- Restore required channels to OPERABLE.	120 days
K. Required Action and associated Completion Time of Condition J not met.	K.1	Reduce THERMAL POWER to < 21% RTP.	4 hour

SURVEILLANCE REQUIREMENTS

-----NOTES-----

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.1.2	-----NOTE----- Not required to be performed until 12 hours after THERMAL POWER ≥ 21.8% RTP. ---------- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power ≤ 2% RTP while operating at ≥ 21.8% RTP.	7 days
SR 3.3.1.1.3	-----NOTE----- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.4	Perform CHANNEL FUNCTIONAL TEST.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.11	Perform CHANNEL FUNCTIONAL TEST.	18 months
SR 3.3.1.1.12	-------------------NOTES------------------ 1. Neutron detectors are excluded. 2. For IRMs, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL CALIBRATION.	18 months
SR 3.3.1.1.13	Perform LOGIC SYSTEM FUNCTIONAL TEST.	18 months
SR 3.3.1.1.14	Verify Turbine Stop Valve Closure, Trip Oil Pressure - Low and Turbine Control Valve Fast Closure Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 35.4% RTP.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.20	------------------NOTE------------------ 1. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. 2. For Functions 2.a, 2.b, and 2.c, the APRM/OPRM channels and the 2-Out-Of-4 Voter channels are included in the CHANNEL FUNCTIONAL TEST. 3. For Functions 2.d and 2.f, the APRM/OPRM channels and the 2-Out-Of-4 Voter channels plus the flow input function, excluding the flow transmitters, are included in the CHANNEL FUNCTIONAL TEST. --- Perform CHANNEL FUNCTIONAL TEST.	184 days
SR 3.3.1.1.21	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.22	-----------------NOTE-------------------- For Function 2.e, "n" equals 8 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. Testing APRM and OPRM outputs shall alternate. --- Verify the RPS RESPONSE TIME is within limits.	24 months on a STAGGERED TEST BASIS
SR 3.3.1.1.23	Verify OPRM is not bypassed when APRM Simulated Thermal Power is greater than or equal to 26% RTP and recirculation drive flow is less than 60% of rated recirculation drive flow.	24 months

Table 3.3.1.1-1 (page 1 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux - High	2	3	H	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 122/125 divisions of full scale
	5(a)	3	I	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 122/125 divisions of full scale
b. Inop	2	3	H	SR 3.3.1.1.3 SR 3.3.1.1.13	NA
	5(a)	3	I	SR 3.3.1.1.4 SR 3.3.1.1.13	NA
2. Average Power Range Monitors					
a. Neutron Flux - High, Setdown	2	3(c)	H	SR 3.3.1.1.7 SR 3.3.1.1.10(d)(e) SR 3.3.1.1.19 SR 3.3.1.1.20	≤ 20% RTP
b. Fixed Neutron Flux - High	1	3(c)	G	SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.10(d)(e) SR 3.3.1.1.19 SR 3.3.1.1.20	≤ 119.3% RTP
c. Inop	1,2	3(c)	H	SR 3.3.1.1.20	NA
d. Flow Biased Simulated Thermal Power - High	1	3(c)	G	SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.10(d)(e) SR 3.3.1.1.17 SR 3.3.1.1.19 SR 3.3.1.1.20	(b)
e. 2-Out-Of-4 Voter	1,2	2	H	SR 3.3.1.1.19 SR 3.3.1.1.20 SR 3.3.1.1.21 SR 3.3.1.1.22	NA
f. OPRM Upscale	≥ 21%	3(c)	J	SR 3.3.1.1.7 SR 3.3.1.1.10(d)(e) SR 3.3.1.1.19 SR 3.3.1.1.20 SR 3.3.1.1.23	(f)

(continued)

Table 3.3.1.1-1 (page 2 of 4)
Reactor Protection System Instrumentation

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(b) Two-Loop Operation: 0.58W + 59.1% RTP and ≤ 113% RTP
Single-Loop Operation: 0.58W + 37.4% RTP

(c) Each channel provides inputs to both trip systems.

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

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

(f) The setpoint for the OPRM Upscale Period-Based Detection algorithm is specified in the COLR.

Table 3.3.1.1-1 (page 3 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. Reactor Vessel Steam Dome Pressure - High	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 1079.7 psig
4. Reactor Vessel Water Level - Low, Level 3	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.15	≥ 10.8 inches
5. Reactor Vessel Water Level - High, Level 8	≥ 21.8% RTP	2	F	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 54.1 inches
6. Main Steam Isolation Valve - Closure	1	8	G	SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 7% closed
7. Drywell Pressure - High	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 1.43 psig
8. Scram Discharge Volume Water Level - High					
a. Transmitter/Trip Unit	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 63% of full scale
	5[a]	2	I	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 63% of full scale
b. Float Switch	1,2	2	H	SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 65 inches
	5[a]	2	I	SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 65 inches

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

Table 3.3.1.1-1 (page 4 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
9. Turbine Stop Valve Closure, Trip Oil Pressure - Low	≥ 35.4% RTP	4	E	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≥ 37 psig
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥ 35.4% RTP	2	E	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≥ 42 psig
11. Reactor Mode Switch - Shutdown Position	1,2	2	H	SR 3.3.1.1.11 SR 3.3.1.1.13	NA
	5[(a)]	2	I	SR 3.3.1.1.11 SR 3.3.1.1.13	NA
12. Manual Scram	1,2	2	H	SR 3.3.1.1.4 SR 3.3.1.1.13	NA
	5[(a)]	2	I	SR 3.3.1.1.4 SR 3.3.1.1.13	NA

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.

3.3 INSTRUMENTATION

3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

LCO 3.3.4.1

a. Two channels per trip system for each EOC-RPT instrumentation Function listed below shall be OPERABLE:

1. Turbine Stop Valve (TSV) Closure, Trip Oil Pressure - Low; and

2. Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure - Low.

OR

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for inoperable EOC-RPT as specified in the COLR are made applicable.

APPLICABILITY: THERMAL POWER ≥ 35.4% RTP with any recirculation pump in fast speed.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required channels inoperable.	A.1	Restore channel to OPERABLE status.	72 hours
	OR		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 -------NOTE------------ Not applicable if inoperable channel is the result of an inoperable breaker. ------------------------ Place channel in trip.	72 hours
B. One or more Functions with EOC-RPT trip capability not maintained. AND MCPR limit for inoperable EOC-RPT not made applicable.	B.1 Restore EOC-RPT trip capability. OR B.2 Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	2 hours 2 hours
C. Required Action and associated Completion Time not met.	C.1 Remove the associated recirculation pump fast speed breaker from service. OR C.2 Reduce THERMAL POWER to < 35.4% RTP.	4 hours 4 hours

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains EOC-RPT trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.1	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.1.2	Calibrate the trip units.	92 days
SR 3.3.4.1.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. TSV Closure, Trip Oil Pressure - Low: ≥ 37 psig. b. TCV Fast Closure, Trip Oil Pressure - Low: ≥ 42 psig.	18 months
SR 3.3.4.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.	18 months
SR 3.3.4.1.5	Verify TSV Closure, Trip Oil Pressure - Low and TCV Fast Closure, Trip Oil Pressure - Low Functions are not bypassed when THERMAL POWER is ≥ 35.4% RTP.	18 months

(continued)

Table 3.3.6.1-1 (page 1 of 5)
Primary Containment and Drywell Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level - Low Low Low, Level 1	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7 SR 3.3.6.1.8	≥ -152.5 inches
b. Main Steam Line Pressure - Low	1	2	E	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7 SR 3.3.6.1.8	≥ 837 psig
c. Main Steam Line Flow - High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7 SR 3.3.6.1.8	≤ 255.9 psid
d. Condenser Vacuum - Low	1,2[(a)], 3[(a)]	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ 8.7 inches Hg vacuum
e. Main Steam Tunnel Ambient Temperature - High	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≤ 191°F
f. Manual Initiation	1,2,3	2	G	SR 3.3.6.1.7	NA
2. Primary Containment and Drywell Isolation					
a. Reactor Vessel Water Level - Low Low, Level 2	1,2,3	2[(b)]	H	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ -43.8 inches

(continued)

(a) With any turbine stop valve not closed.

(b) Also required to initiate the associated drywell isolation function.

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.4.3.1	-----------------NOTES------------------ 1. Not required to be performed until 4 hours after associated recirculation loop is in operation. 2. Not required to be performed until 24 hours after > 21.8% RTP. -- Verify at least two of the following criteria (a, b, and c) are satisfied for each operating recirculation loop: a. Recirculation loop drive flow versus flow control valve position differs by ≤ 10% from established patterns. b. Recirculation loop drive flow versus total core flow differs by ≤ 10% from established patterns. c. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns, or each jet pump flow differs by ≤ 10% from established patterns.	24 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 Safety/Relief Valves (S/RVs)

LCO 3.4.4 The safety function of nine S/RVs shall be OPERABLE

AND

The relief function of six additional S/RVs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required S/RVs inoperable.	A.1 Be in MODE 3. AND A.2 Be in MODE 4.	12 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.4.1	Verify the safety function lift setpoints of the required S/RVs are as follows: Number of S/RVs — Setpoint (psig) 8 — 1165 ± 34.9 6 — 1180 ± 35.4 6 — 1190 ± 35.7	In accordance with the Inservice Testing Program

(continued)

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.11 RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation loop temperature requirements shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------NOTE---------- Required Action A.2 shall be completed if this Condition is entered. --------------------	A.1 Restore parameter(s) to within the limits specified in the PTLR.	30 minutes
	AND	
Requirements of the LCO not met in MODES 1, 2, and 3.	A.2 Determine RCS is acceptable for continued operation.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3.	12 hours
	AND	
	B.2 Be in MODE 4.	36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. --------NOTE--------- Required Action C.2 shall be completed if this Condition is entered. -------------------- Requirements of the LCO not met in other than MODES 1, 2, and 3.	C.1	Initiate action to restore parameter(s) to within the limits specified in the PTLR.	Immediately
	<u>AND</u>		
	C.2	Determine RCS is acceptable for operation.	Prior to entering MODE 2 or 3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	-----------------NOTE------------------ Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. -- Verify: a. RCS pressure and RCS temperature are within the limits specified in the PTLR based on the current Effective Full Power Year (EFPY), and b. RCS heatup and cooldown rates are within the limits specified in the PTLR.	30 minutes

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.2	------------------NOTE------------------ Only required to be met during control rod withdrawal for the purpose of achieving criticality. -- Verify RCS pressure and RCS temperature are within the criticality limits specified in the PTLR based on the current Effective Full Power Year (EFPY).	Once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality
SR 3.4.11.3	----------------NOTE-------------------- Only required to be met in MODES 1, 2, 3, and 4 with reactor steam dome pressure ≥ 25 psig during recirculation pump start. -- Verify the difference between the bottom head coolant temperature and the reactor pressure vessel (RPV) coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.11.4	-------------------NOTE------------------ Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump start. -- Verify the difference between the reactor coolant temperature in the recirculation loop to be started and the RPV coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to each startup of a recirculation pump

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.5	-------------------NOTE------------------ Only required to be performed when tensioning the reactor vessel head bolting studs. --- Verify reactor vessel flange and head flange temperatures are within the limits specified in the PTLR.	30 minutes
SR 3.4.11.6	------------------NOTE------------------- Not required to be performed until 30 minutes after RCS temperature ≤ 80°F in MODE 4. --- Verify reactor vessel flange and head flange temperatures are within the limits specified in the PTLR.	30 minutes
SR 3.4.11.7	-----------------NOTE------------------- Not required to be performed until 12 hours after RCS temperature ≤ 100°F in MODE 4. --- Verify reactor vessel flange and head flange temperatures are within the limits specified in the PTLR.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.8	------------------NOTE-------------------- Only required to be met in single loop operation during increases in THERMAL POWER or recirculation loop flow with the operating recirculation pump not on high speed and THERMAL POWER < 36% of RTP. --- Verify the difference between the bottom head coolant temperature and the RPV coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow
SR 3.4.11.9	------------------NOTE-------------------- Only required to be met in single loop operation during increases in THERMAL POWER or recirculation loop flow with the operating recirculation pump not on high speed, and THERMAL POWER < 36% of RTP, and the idle recirculation loop not isolated from the RPV. --- Verify the difference between the reactor coolant temperature in the recirculation loop not in operation and the RPV coolant temperature is within the limits specified in the PTLR.	Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow

Next page is 3.4-36.

3.7 PLANT SYSTEMS

3.7.7 Main Turbine Bypass System

LCO 3.7.7

a. The Main Turbine Bypass System shall be OPERABLE with two Main Turbine Bypass Valves.

OR

b. The following limits are made applicable:

1. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

AND

2. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

APPLICABILITY: THERMAL POWER $\geq$ 70% RTP

ACTION

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Requirements of the LCO not met or Main Turbine Bypass System is inoperable.	A.1	Satisfy the Requirements of the LCO or restore the Main Turbine Bypass System to OPERABLE status.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Reduce THERMAL POWER to < 70% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	Verify one complete cycle of each main turbine bypass valve.	31 days
SR 3.7.7.2	Perform a system functional test.	18 months

5.5 Programs and Manuals (continued)

5.5.11 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

1. A change in the TS incorporated in the license; or

2. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the UFSAR.

d. Proposed changes that do not meet the criteria of either Specification 5.5.11.b.1 or Specification 5.5.11.b.2 above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.12 10 CFR 50, Appendix J, Testing Program

This program establishes the leakage rate testing program of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be implemented in accordance with the Safety Evaluation issued by the Office of Nuclear Reactor Regulation dated April 26, 1995 (GNRI-95/00087) as modified by the Safety Evaluation issued for Amendment No. 135 to the Operating License, except that the next Type A test performed after the November 24, 1993 Type A test shall be performed no later than November 23, 2008. Consistent with standard scheduling practices for Technical Specifications required surveillances, intervals for the recommended surveillance frequency for Type A, B and C testing may be extended by up to 25 percent of the test interval, not to exceed 15 months. The calculated peak containment internal pressure for the design basis loss of coolant accident, Pa, is 14.8 psig.

5.6 Reporting Requirements

5.6.6 Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)

a. RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

   i) Limiting Conditions for Operations Section 3.4.11, "RCS Pressure and Temperature (P/T) Limits"

   ii) Surveillance Requirements Section 3.4.11, "RCS Pressure and Temperature (P/T) Limits"

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

   i) NEDC-33178P-A, "GE Hitachi Nuclear Energy Methodology for Development of Reactor Pressure Vessel Temperature Curves" Revision 1, June 2009

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

ENCLOSURE 2

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR

REGULATION RELATED TO AMENDMENT NO. 191

TO FACILITY OPERATING LICENSE NO. NPF-29

ENTERGY OPERATIONS, INC.

GRAND GULF NUCLEAR STATION, UNIT 1

DOCKET NO. 50-416

Proprietary information pursuant to Section 2.390 of Title 10 of
the *Code of Federal Regulations* has been redacted from this document.

Redacted information is identified by blank space enclosed within double brackets.

GRAND GULF NUCLEAR STATION, UNIT 1

SAFETY EVALUATION FOR EXTENDED POWER UPRATE

TABLE OF CONTENTS

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO

AMENDMENT NO. 191 TO FACILITY OPERATING LICENSE NO. NPF-29

ENTERGY OPERATIONS, INC.

GRAND GULF NUCLEAR STATION, UNIT 1

DOCKET NO. 50-416

1.0 INTRODUCTION

1.1 Application

By application dated September 8, 2010 (Reference 1), as supplemented by letters dated November 18, 2010 (Reference 2), November 23, 2010 (Reference 3), February 23, 2011 (four letters, References 4, 5, 6, and 7), March 9, 2011 (two letters, References 8 and 9), March 22, 2011 (Reference 10), March 30, 2011 (Reference 11), March 31, 2011 (Reference 12), April 14, 2011 (Reference 13), April 21, 2011 (Reference 14), May 3, 2011 (Reference 15), May 5, 2011 (Reference 16), May 11, 2011 (Reference 17), June 8, 2011 (Reference 18), June 15, 2011 (Reference 19), June 21, 2011 (Reference 20) June 23, 2011 (Reference 21), July 6, 2011 (Reference 22), July 28, 2011 (Reference 23), August 25, 2011 (Reference 24), August 29, 2011 (Reference 25), August 30, 2011 (Reference 26), September 2, 2011 (Reference 27), September 9, 2011 (Reference 28), September 12, 2011 (Reference 29), September 15, 2011 (Reference 30), September 26, 2011 (Reference 31), October 10, 2011 (two letters, References 32 and 33), October 24, 2011 (Reference 34), November 14, 2011 (Reference 35), November 25, 2011 (Reference 36), November 28, 2011 (Reference 37), December 19, 2011 (Reference 38), February 6, 2012 (Reference 39), February 15, 2012 (Reference 40), February 20, 2012 (Reference 41), March 13, 2012 (Reference 42), March 21, 2012 (Reference 43), April 5, 2012 (Reference 44), April 18, 2012 (two letters, References 45 and 46), April 26, 2012 (Reference 47), May 9, 2012 (Reference 48), and June 12, 2012 (Reference 49), Entergy Operations, Inc. (Entergy, the licensee), submitted a license amendment request for Grand Gulf Nuclear Station, Unit 1 (GGNS). Portions of the letters dated September 8 and November 23, 2010, and February 23, April 21, May 11, July 6, July 28, September 2, October 10, November 14, November 25, and November 28, 2011, and February 6, February 15, February 20, March 13, March 21, April 5, April 18, and May 9, 2012, contain sensitive unclassified non-safeguards information (proprietary) and, accordingly, have been withheld from public disclosure.

The supplemental letters dated November 18 and November 23, 2010, and February 23 (four letters), March 9 (two letters), March 22, March 30, March 31, April 14, April 21, May 3, May 5, May 11, June 8, June 15, June 21, June 23, July 6, July 28, August 25, August 29, August 30, September 2, September 9, September 12, September 15, September 26, October 10 (two letters), October 26, November 14, November 25, and November 28, 2011, and February 6, February 15, February 20, March 13, March 21, April 5, April 18 (two letters), April 26, May 9, and June 12, 2012, provided additional clarifying information that did not expand the scope of the initial application and did not change the U.S. Nuclear Regulatory Commission (NRC or the Commission) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on January 10, 2011 (76 FR 1464).

The proposed changes would increase the maximum steady-state reactor core power level from 3,898 megawatts thermal (MWt) to 4,408 MWt, which is an increase of approximately 15 percent from the original licensed thermal power (OLTP) level of 3,833 MWt. The proposed increase in power level is considered an extended power uprate (EPU).

1.2 Background

GGNS is a boiling-water reactor (BWR) plant of the BWR/6 design with a Mark-III containment. The NRC licensed GGNS on November 1, 1984, under NPF-29 (Reference 50), for full-power operation at the OLTP of 3,833 MWt, and GGNS entered commercial operation on July 1, 1985. In License Amendment No. 156, dated October 10, 2002 (Reference 51), the GGNS licensed thermal power limit was increased by approximately 1.7 percent from 3,833 MWt to 3,898 MWt (i.e., the current power level). The 1.7 percent power change was based on the installation of the Caldon Leading Edge Flow Meter ultrasonic flow measurement system and its ability to achieve increased accuracy in measuring feedwater flow.

The GGNS site is located in Claiborne County, Mississippi, on the east bank of the Mississippi River at River Mile 406, approximately 25 miles south of Vicksburg, Mississippi, and 37 miles north-northeast of Natchez, Mississippi. Port Gibson, located approximately 6 miles to the southeast, is the closest town to the GGNS site with a 2010 Census population of 1,567.

The construction permit for GGNS was issued by the Atomic Energy Commission (AEC) on September 4, 1974 (Reference 52). The plant was designed and constructed based on Appendix A to Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, "General Design Criteria for Nuclear Power Plants," in the *Federal Register* (36 FR 3255) on February 20, 1971 (hereinafter referred to as "final GDC"). The 64 GDCs establish minimum requirements for the principal design criteria for water-cooled nuclear power plants including GGNS.

As discussed in the GGNS Updated Final Safety Analysis Report (UFSAR) (Reference 53), Section 3.1, "Conformance with the NRC General Design Criteria," for each of the 64 criteria in the GDC, a specific assessment of the plant design has been made. In addition, a list of GGNS UFSAR sections where further information pertinent to each criterion is also provided.

1.3 Licensee's Approach

The licensee for GGNS applied for an EPU license amendment request (the EPU LAR) by letter dated September 8, 2010 (Reference 1). The licensee's application for the proposed EPU follows the guidance in the NRC Office of Nuclear Reactor Regulation's (NRR's) Review Standard (RS)-001, Revision 0, "Review Standard for Extended Power Uprates," December 2003 (hereafter referred to as RS-001) (Reference 54), to the extent that the review standard is consistent with the design basis of the plant. Where differences exist between the plant-specific design basis and RS-001, the licensee described the differences and provided evaluations consistent with the design basis of the plant. The licensee's application for the proposed GGNS EPU was prepared following the guidelines contained in General Electric (GE) Licensing Topical Report (LTR) NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4, July 2003 (Reference 55). The constant pressure power uprate (CPPU) LTR, hereafter referred to as the CLTR, was approved by the NRC in a final safety evaluation (SE) dated March 31, 2003 (Reference 56). The CLTR provided appropriate guidelines for CPPU applications with a core exclusively using GE fuel. Some topics in the CLTR are directly fuel dependent, because the fuel type affects the resulting evaluation or the consequences of transients or accidents.

Attachment 5B to the licensee's EPU LAR contains GE LTR NEDC-33477P, Revision 0, "Safety Analysis Report for Grand Gulf Nuclear Station, "Constant Pressure Power Uprate," August 2010 (Reference 57), which is the Power Uprate Safety Analysis Report (PUSAR) for GGNS. This proprietary report summarizes the results of safety analyses and evaluations performed by GE, justifying the proposed GGNS EPU. The PUSAR follows the generic content and format using the CPPU approach to uprating reactor power, as described in the CLTR. A non-proprietary (i.e., publicly available) version of the PUSAR is contained in Attachment 5A to the licensee's EPU LAR.

Because GGNS uses GNF2 fuel, the CLTR is not applicable for fuel-design-dependent evaluations and the transients performed in support of the generic disposition in the CLTR are not applicable. Therefore, for fuel-dependent topics, this report follows the NRC-approved generic content for BWR EPU licensing reports, documented in NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate" (ELTR1) (Reference 58). In general, the licensee's plant-specific engineering evaluations supporting the power uprate were performed in accordance with guidance contained in ELTR1. For issues that have been evaluated generically, this report references bounding analyses and evaluations provided in the NRC-approved Topical Report NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate" (ELTR2) (Reference 59).

By performing the power uprate in accordance with the CLTR, ELTR1, ELTR2, and their NRC Safety Evaluation Reports (SERs), the evaluation scope of the plant safety analyses and system performance is reduced, thus allowing for a more streamlined process.

The approach to achieving a CPPU for GGNS consists of: (1) an increase in the core thermal power with a more uniform power distribution achieved by better fuel management techniques to create increased steam flow; (2) a corresponding increase in the feedwater system flow; (3) no increase in maximum core flow; and (4) reactor operation primarily along the maximum extended load line limit analysis (MELLLA) rod/flow lines. However, there is no increase in the maximum normal operating reactor vessel dome pressure or the maximum licensed core flow over their pre-EPU values. EPU operation does not involve increasing the maximum normal operating reactor vessel dome pressure, because the plant, after modifications to non-safety power generation equipment, has sufficient pressure control and turbine flow capabilities to control the inlet pressure conditions at the turbine. As noted above, this approach is based on the NRC-approved BWR EPU guidelines contained in the CLTR, ELTR1, and ELTR2 topical reports.

The proposed method for achieving the higher steam flow necessary for the proposed 15 percent EPU for GGNS, would be accomplished by retaining the existing MELLLA power/flow map and increasing core flow (and power) along the MELLLA upper boundary line as shown in Figure 1-1 in the PUSAR (Reference 57). The current MELLLA power/flow map was approved in GGNS Amendment No. 156, dated October 10, 2002 (Reference 51). As discussed in Section 2.8.2 of the PUSAR, the additional energy requirements for CPPU are met by an increase in the bundle enrichment, an increase in the reload fuel batch size, and/or changes in fuel loading pattern to maintain the desired plant operating cycle length.

Entergy, the licensee for GGNS, referenced GE LTR NEDC-33173P, "Applicability of GE Methods to Expanded Operating Domains," July 21, 2009 (Reference 60), in its application. This report, also known as the Interim Methods Licensing Topical Report (IMLTR), is based on the NRC staff-approved approach taken by the Vermont Yankee Nuclear Generating Station (Vermont Yankee) for applying the GE analytical methods for CPPU operating domains.

The NRC staff's SE for NEDC-33173P, "Applicability of GE Methods to Expanded Operating Domains," dated January 17, 2008 (Reference 61), specifies the limitations that apply to NEDC-33173P.

Entergy referenced NEDC-33173P to justify application of GE methods to the GGNS EPU. Each limitation specified in the NRC staff's SE for NEDC-33173P was evaluated for acceptability for the GGNS EPU. In addition, the NRC staff's evaluation of applicability of NEDC-33173P, specifically to GNF2 for GGNS Cycle 19, is discussed in Section 2.8.2.4 of this SE.

Table 1-2 of the PUSAR provides a summary of the reactor thermal-hydraulic parameters for current licensed thermal power (CLTP) plant operating conditions and CPPU/GGNS EPU operating conditions (Attachment 5, pages 1-13 of the Reference 1).

For the replacement steam dryer evaluation, the licensee used evaluation methods described in the Steam Dryer Analysis Report (SDAR), which was originally submitted as Attachment 11 to the EPU LAR. Revision 1 of the SDAR was issued in Entergy's letter dated February 20, 2012 (Reference 41). This report describes a plant-specific analysis of the steam dryer, including a plant-based load evaluation (PBLE) methodology to identify the acoustic loadings to which the steam dryer is designed. The NRC evaluation of this analysis is discussed in Section 2.2.6 of this SE.

The licensee plans to implement the EPU in one step. The licensee made a majority of the modifications necessary to implement the EPU during the refueling outage that began in February 2012. Subsequent to the completion of the modifications and NRC approval, the plant will be operated at 4,408 MWt starting in Cycle 19.

1.4 Plant Modifications

The licensee has determined that several plant modifications are necessary to implement the proposed EPU. The following is a list of these modifications and the licensee's proposed schedule for completing them.

- Auxiliary Cooling Tower Expansion, modification completed

- Standby Service Water Cooling Tower Upgrade, modification completed

The following major modifications were completed prior to startup from the spring 2012 refueling outage:

- Upgrade Local Transmission System, including Capacitor Banks
- Radial (Ranney) Well Addition
- Replace Reactor Feed Pump Turbine Rotor
- Increase Standby Liquid Control System Boron Enrichment
- Install Power Range Neutron Monitoring System (regulatory review completed under separate licensing action)
- Replace Steam Dryer
- Replace Iso-Phase Bus Duct Cooling
- Replace Main Transformer
- Staking/ Repairs to Main Condenser Tubes
- Increase Ultimate Heat Sink Inventory
- Replace High Pressure Turbine
- Upgrade Seal Oil Skid
- Refurbish Generator and Exciter Hydrogen Cooler
- Refurbish Generator Rotor and Stator
- Replace Moisture Separator Reheater and relief valves
- Replace Fuel Pool Cooling Heat Exchanger
- Install Condensate Full Flow Filtration System
- Component Cooling Water Heat Exchanger Tube Cleaning System installation
- Replace Low Pressure Feedwater Heaters (9)
- Feedwater Heater Level Control Valve Instrumentation

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

1.5 Method of NRC Staff Review

The NRC staff's review of the GGNS EPU application is based on RS-001 (Reference 54). RS-001 contains guidance for evaluating each area of review in the application, including the specific GDC used as the NRC's acceptance criteria. The guidance in RS-001 is based on the final GDC. In addition to RS-001, the NRC staff used applicable rules, regulatory guides, NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [Light-Water Reactor] Edition," March 2007 (SRP) (Reference 62) sections, and NRC staff positions on the topics being evaluated.

The NRC staff review is outlined to provide 1) the regulatory evaluation related to each specific technical review area, including applicable acceptance criteria, 2) a summary of the licensee's evaluation supporting EPU implementation with regards to a specific technical area and 3) the NRC staff's evaluation and conclusion of the information provided by the licensee within each associated technical area. The NRC staff's evaluation was performed in accordance with the acceptance criteria outlined within the regulatory evaluation of each technical review area.

The NRC staff requested that the licensee identify all codes and methodologies used to obtain safety limits and operating limits and explain how it verified these limits were correct for the uprate reactor core. The NRC also requested the licensee to identify and discuss any limitations imposed by the NRC staff on the use of these codes and methodologies.

The NRC staff reviewed the licensee's application to ensure that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; (2) there is reasonable assurance that such activities proposed will be conducted in compliance with the Commission's regulations; and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

The purpose of the NRC staff's review is to evaluate the licensee's assessment of the impact of the proposed GGNS EPU on design-basis analyses. The NRC staff evaluated the licensee's application and supplements. The NRC staff also performed audits, independent calculations, analyses, and evaluations as noted below.

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

Audits supporting the proposed GGNS EPU were conducted by the NRC staff and its contractors in relation to the following topics:

- steam dryer structural integrity (see SE Section 2.2.6)
- review of calculations supporting the Main Steam Line (MSL) Flow – High Allowable Value (AV) and Nominal Trip Setpoint (NTSP), Fixed Neutron Flux – High AV and NTSP, and Average Power Range Monitor (APRM) Flow-Biased Thermal Power – High AV and NTSP setpoint changes (see SE Section 2.4.1.3, "Instrument Setpoint Methodology").

- review of long-term (L/T) Stability Option and anticipated transients without scram (ATWS) systems. This audit had two main goals: (1) to understand the implementation status of the GGNS L/T Stability Option implementations, and (2) to review the implementation of the ATWS emergency operating procedures (EOPs), including the ATWS/Stability mitigation actions, as it relates to the EPU upgrade (see SE Section 2.8.3, "Thermal and Hydraulic Design").

Independent confirmatory calculations, analyses, and evaluations were performed by the NRC staff and its contractors in relation to the following topics:

- reactor vessel pressure-temperature limits and upper-shelf energy (see SE Section 2.1.2)

- containment review (see SE Section 2.6)

- mechanical engineering steam dryer and non-steam dryer reviews (see SE Section 2.2)

- emergency core cooling system (ECCS) performance (see SE Section 2.8.5.6.2)

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material Surveillance Program

Regulatory Evaluation

The reactor pressure vessel (RPV) material surveillance program provides a means for monitoring the fracture toughness of the RPV beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the RPV. The regulations in 10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements," provide the NRC's requirements for the design and implementation of the RPV material surveillance program. The NRC staff's reviewed the effects of the proposed EPU on the licensee's RPV surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on (1) 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 abnormal leakage, of rapidly propagating failure, and of gross rupture; (2) GDC 31, "Fracture prevention of reactor coolant pressure boundary," which requires that the RCPB be designed with sufficient margin to assure that, when stressed under operating, maintenance, testing, and postulated accident conditions, the boundary behaves in a non-brittle manner and that the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides requirements for monitoring changes in the fracture toughness properties of ferritic materials in the RPV beltline region; and (4) 10 CFR 50.60, "Acceptance criteria for fracture prevention measures for lightwater nuclear power reactors for normal operation," which requires in part, all light-water reactors to meet Appendix H to 10 CFR Part 50. Specific review criteria are contained in SRP Section 5.3.1, "Reactor Vessel Materials" (Reference 62), and other guidance provided in Matrix 1 of RS-001 (Reference 54).

The NRC's regulatory requirements related to the establishment and implementation of a facility's RPV materials surveillance program and surveillance capsule withdrawal schedule are given in Appendix H to 10 CFR Part 50. By reference, Appendix H to 10 CFR Part 50 invokes 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 E185) (Reference 63), specifically the -73, -79, and -82 editions of the standard. ASTM E185 provides guidelines for designing and implementing the RPV materials surveillance programs for operating light-water reactors (LWRs), including guidelines for determining RPV surveillance capsule withdrawal schedules based on the vessel material predicted reference temperature for nil ductility transition shifts (ΔRT_{NDT}).

As an alternative to a plant surveillance program implemented consistent with ASTM E185, Appendix H to 10 CFR Part 50 allows for the implementation of an integrated surveillance program (ISP). An ISP is defined in Appendix H to 10 CFR Part 50 as occurring when, "the representative materials chosen for surveillance for a reactor are irradiated in one or more other reactors that have similar design and operating features."

Technical Evaluation

The licensee discussed the impact of the EPU on the RPV material surveillance program in Section 2.1.1 of the GGNS EPU LAR, which is part of the Boiling Water Reactor Vessel and Internals Program (BWRVIP) ISP. The licensee stated that the GGNS RPV surveillance program consists of three capsules, none of which have been tested. One capsule containing Charpy impact test specimens was removed from the RPV during Refueling Outage (RFO) 7 and returned during RFO 8, and the remaining two capsules have been in the RPV since start-up. GGNS is not designated as a representative plant for the BWRVIP ISP and no capsules are currently slated for removal. Therefore, the licensee concluded that the current surveillance capsule withdrawal schedule is still valid for the EPU conditions.

BWRVIP-86-A, "BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Plan Program Implementation Plan," dated October 2002 (Reference 64), establishes the ISP requirements for RPV base and weld metal in all operating BWRs for the first 40-year operating period, including GGNS. The NRC's final SE for BWRVIP-86-A dated February 1, 2002 (Reference 65), confirms that the ISP requirements are compliant with the ISP requirements established in Appendix H to 10 CFR Part 50. The ISP provides for a number of surveillance capsules to be removed from specified BWRs and to be available for testing during the license renewal period for the BWR fleet. The ISP establishes acceptable technical criteria for capsule withdrawal and testing. The NRC staff verified that the proposed EPU will have no impact on the licensee's effective implementation of the BWRVIP ISP because it is not a representative plant. The ISP program materials in GGNS are bounded by capsule materials found in other plants. Therefore, the NRC staff concludes that the licensee's RPV material surveillance program for GGNS will remain in compliance with the requirements specified in Appendix H to 10 CFR Part 50 under EPU conditions.

Based on the above, the NRC staff concludes that the licensee has satisfied the requirements of Appendix H to 10 CFR Part 50.

Conclusion

The NRC staff concludes that the licensee has adequately addressed the impact of the proposed EPU on the RPV material surveillance program at GGNS. The NRC staff further concludes that the licensee's implementation of the BWRVIP ISP at GGNS is appropriate to ensure that the material surveillance program will continue to meet the requirements of Appendix H to 10 CFR Part 50 and 10 CFR 50.60, and will provide the licensee with information to ensure continued compliance with GDCs 14 and 31, following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the RPV material surveillance program.

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy

Regulatory Evaluation

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

The NRC's acceptance criteria are based on (1) GDC 14, "Reactor coolant pressure boundary," 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, "Fracture prevention of reactor coolant pressure boundary," which requires that the RCPB be designed with sufficient margin to assure that, when stressed under operating, maintenance, testing, and postulated accident conditions, the boundary behaves in a non-brittle manner and that the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides requirements for monitoring changes in the fracture toughness properties of ferritic materials in the RPV beltline region; and (4) 10 CFR 50.60, "Acceptance criteria for fracture prevention measures for lightwater nuclear power reactors for normal operation," which requires, in part, all light-water reactors to meet Appendix H to 10 CFR Part 50. Specific review criteria are contained in SRP Section 5.3.2, "Pressure-Temperature Limits, Upper-Shelf Energy, and Pressurized Thermal Shock" (Reference 62).

Technical Evaluation

USE Calculations

The regulations in Appendix G to 10 CFR Part 50 provide the NRC staff's criteria for maintaining acceptable levels of USE for the RPV beltline materials of operating reactors throughout the licensed operational lives of the facilities. The rule requires RPV beltline materials to have a minimum USE value of 75 foot-pounds (ft-lb) initially (i.e., in the unirradiated condition) and to maintain a minimum USE value above 50 ft-lb throughout the life of the RPV, unless it is demonstrated in a manner approved by the NRC that lower values of USE would provide margins of safety against fracture equivalent to those required by Appendix G of the ASME Code, Section XI. The rule also requires that the methods used to calculate USE values must account for the effects of neutron radiation on the USE values for the materials and must incorporate any relevant RPV surveillance capsule data that are reported through implementation of a plant's Appendix H to 10 CFR Part 50 RPV materials surveillance program. The NRC staff's recommended guidelines for calculating the effects of neutron radiation on the USE values for the RPV beltline materials are specified in NRC Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," May 1988 (Reference 66).

Projected USE values for RPV materials are calculated based on the projected neutron fluence at a postulated flaw depth at a location of one-quarter of the vessel wall thickness from the clad/base metal interface of the RPV (1/4T), weight percentage (wt. %) of copper (Cu) in the material, and the initial USE value for the material prior to exposure to neutron radiation. Initial USE values are available for the GGNS beltline, therefore, direct calculation of projected USE values is used by the licensee to determine compliance with the USE requirements of 10 CFR Part 50, Appendix G.

The licensee summarized the USE calculations conducted in Table 2.1-1 of the GGNS PUSAR, using RG 1.99, Revision 2. The licensee demonstrated that all RPV beltline materials at GGNS will satisfy the requirements of Appendix G to 10 CFR Part 50 and that the lowest projected end-of-license (EOL) USE is 79.6 ft-lb for weld heat 5P6214B/0331. The licensee provided the wt. % Cu values and projected 35 effective full power years (EFPY) peak neutron fluence values at the 1/4T location for all RPV beltline materials. In addition, the GGNS plant-specific analysis is shown to be consistent with data from the ISP (both best-estimate chemistries and ISP data). Finally, the NRC staff independently verified the percentage decrease in USE at the 1/4T location, assuming the licensee's 35 EFPY 1/4T neutron fluence under EPU conditions. Therefore, the NRC staff concludes that the GGNS RPV beltline materials will maintain sufficient USE for the remainder of the initial 40-year licensed operating period.

P-T Limit Calculations

Section IV.A.2 of 10 CFR Part 50, Appendix G requires that the P-T limits for operating reactors be at least as conservative as limits obtained by following the methods of analysis and the margins of safety of the ASME Code, Section XI, Appendix G. The rule also requires that the P-T limit calculations account for the effects of neutron radiation on the material properties of the RPV beltline materials and that P-T limit calculations incorporate any relevant RPV surveillance capsule data that are reported as part of the licensee's implementation of its 10 CFR Part 50, Appendix H, RPV materials surveillance program. The NRC staff's recommended guidelines for calculating the effects of neutron radiation on the adjusted reference temperature (ART) values used for P-T limit calculations are specified in RG 1.99, Revision 2.

Two sets of P-T limits were provided in the GGNS EPU LAR. P-T limits in Section 2.1.2 of the EPU LAR pertain to current P-T limits in the GGNS TSs. P-T limits in Attachment 7 of GGNS's EPU LAR are generated using a Pressure and Temperature Limits Report (PTLR). By letter dated February 23, 2011 (Reference 5), in response to an NRC staff request for additional information (RAI) dated January 31, 2011 (Reference 67), GGNS clarified that only P-T limits generated in accordance with the PTLR would apply during the proposed EPU. The NRC staff has not reviewed the current P-T limits in the TSs and discussed in Section 2.1.2 of the submittal, as they are not applicable during EPU operation. The PTLR methodology used by the licensee to generate P-T limits required a more extensive review and is addressed in Section 2.1.8 of this SE. In its evaluation of the PTLR, the NRC staff concludes that the proposed P-T limits are valid for 35 EFPY and satisfy the requirements of Appendix G to Section XI of the ASME Code and Appendix G to 10 CFR Part 50, based on independent verification of the proposed PTLR methodology. P-T limits generated using the licensee's PTLR methodology account for the effect of the EPU on RPV embrittlement by shifting P-T limits based on the ART of the limiting material. ART values calculated by the licensee evaluate the extended beltline region and incorporate relevant surveillance data collected through the ISP, satisfying the requirements of Appendix H to 10 CFR Part 50. Based on the above, the NRC staff concludes that the PTLR is acceptable for EPU conditions.

RPV Circumferential Weld Properties

The ASME Code, Section XI, Table IWB-2500-1 requires inspection of all RPV welds at regular intervals. On April 11, 2001, the NRC granted the licensee relief from performing the ASME Code, Section XI-required examinations of the GGNS RPV circumferential welds for the original 40-year licensed operating period, under pre-EPU operating conditions (Reference 68). The basis for this relief was the BWRVIP-05 report, "BWR Reactor Pressure Vessel Shell Weld Inspection Recommendation," dated July 28, 1998 (Reference 69), which concluded that the conditional failure probabilities for BWR RPV circumferential shell welds are orders of magnitude lower than those of the axial shell welds. The NRC evaluated the BWRVIP-05 report and allowed licensees to use it as a technical basis for requesting relief from circumferential shell weld examinations, provided the licensee demonstrates that its plant-specific RPV circumferential shell weld parameters are bounded by those in the BWRVIP-05 report. The GGNS RPV circumferential weld parameters prior to EPU operating conditions are bounded by the BWRVIP-05 report and this is the basis for granting relief to the licensee from performing volumetric examinations of the RPV circumferential welds for the remainder of the original 40-year licensed operating term.

In the case of GGNS, there are no circumferential welds within the beltline region. As such, circumferential welds AB and AC could be considered to be the limiting welds which are located 5 inches below the bottom of the active fuel region and 22 inches above the top of the active fuel region, respectively. The corresponding neutron fluence values (E > 1.0 million electron Volts (MeV)) were assumed to be the peak value calculated at the EOL within the active fuel region. In addition, no credit was taken for the stainless steel vessel cladding. The EOL neutron fluence value is predicted to be 0.253×10^{19} n/cm^2 for both AB and AC welds at EOL.

The NRC staff's SE provides a limiting conditional failure probability of 2×10^{-7} per reactor year for a limiting plant-specific mean RT_{NDT} of 44.5 degrees Fahrenheit (°F) for Chicago Bridge and Ironworks (CB&I) fabricated RPVs. Comparing the information submitted in the relief request, the NRC staff has confirmed that the mean RT_{NDT} of the circumferential welds at GGNS is projected to be 13.9 °F at the end of the current license. In this evaluation, the chemistry factor, ΔRT_{NDT}, and mean RT_{NDT} were calculated consistent with the guidelines of RG 1.99, Revision 2. The calculated value of mean RT_{NDT} for the circumferential welds at GGNS is significantly lower than that for the limiting plant-specific case for CB&I-fabricated RPVs, indicating that the conditional failure probability of the GGNS circumferential welds is much less than 2 x 10^{-7} per reactor year. Based on the above, the NRC staff concludes that the GGNS RPV circumferential weld parameters will continue to be bounded by the BWRVIP-05 parameters discussed above.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the USE, P-T limits, and RPV circumferential weld properties. The NRC staff concludes that the licensee has adequately addressed the impact of the EPU on the GGNS USE, P-T limits, and RPV circumferential weld properties. Specifically, the NRC staff concludes that (1) the GGNS RPV beltline materials will remain acceptable, with respect to the USE, under EPU conditions, through the EOL for the facility (35 EFPY); (2) the licensee's PTLR has addressed the impact of the EPU on the ART values for the RPV beltline materials; and (3) the RPV circumferential weld properties will remain bounded by the NRC failure probability analysis from Appendix A to BWRVIP-05 under EPU conditions through 35 EFPY. Based on the above, the NRC staff concludes that GGNS will continue to meet the requirements of Appendix G to 10 CFR Part 50, 10 CFR 50.60, GDCs 14 and 31 following implementation of the proposed EPU.

2.1.3 Reactor Internal and Core Support Materials

Regulatory Evaluation

The reactor vessel internals (RVI) components include structures, systems, and components (SSCs) that perform safety functions or whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the reactor coolant system (RCS)). The NRC staff reviewed the materials' specifications, mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation for these components. The NRC's acceptance criteria for RVI and core support materials are based on GDC 1, "Quality standards and records," and 10 CFR 50.55a, "Codes and standards." Specific review criteria are contained in SRP Section 4.5.2, "Reactor Internal and Core Support Structure Materials" (Reference 62), and other review criteria and guidance are provided in Matrix 1 of RS-001 (Reference 54).

Technical Evaluation

The licensee discussed the impact of the EPU on the structural integrity of the GGNS RVI components in Sections 2.1.3 and 2.1.4 of the GGNS EPU LAR. The licensee assessed the RVI components and found them acceptable for continued operation through the EOL operating period (35 EFPY) under EPU conditions.

The licensee's RVI and core support materials evaluation addresses the materials specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation of the RVI and core supports. The licensee's RVI and core support materials evaluation indicated that the RVI and core support materials will continue to be acceptable under EPU conditions and will continue to meet the requirements of the current licensing basis (CLB) and 10 CFR 50.55a.

The licensee discussed the potential for irradiation-assisted stress-corrosion cracking (IASCC) in RVI and core support components. The licensee stated that the increased neutron fluence resulting from the EPU can create the potential for additional IASCC susceptibility in these components. To address this potential, the licensee has a procedurally controlled program for the augmented nondestructive examination of selected RVI components in order to ensure their continued structural integrity. The inspection techniques utilized are primarily for the detection and characterization of service-induced, surface-connected planar discontinuities, such as intergranular stress-corrosion cracking (IGSCC) and IASCC in welds and adjacent base material.

Components selected for inspection include those that are identified as susceptible to in-service degradation, and augmented examination is conducted for verification of structural integrity. These components have been identified through the review of NRC Inspection Bulletins, BWRVIP documents, and recommendations provided by GE Service Information Letters. The inspection program provides performance frequency for nondestructive examination and associated acceptance criteria. Components inspected include the following:

1. Core spray piping
2. Core plate
3. Core spray spargers
4. Core shroud and core shroud support
5. Jet pumps and associated components
6. Top guide
7. Lower plenum
8. Vessel inside diameter (ID) attachment welds
9. Instrumentation penetrations
10. Steam dryer drain channel welds
11. Feedwater spargers
12. In-core flux monitoring guide tubes
13. Control rod guide tubes

The licensee stated that neutron fluence calculations performed at EPU conditions indicate that three components — top guide, core shroud, and core plate — will exceed the 5×10^{20} n/cm^2 (E > 1 MeV) neutron fluence threshold value for IASCC susceptibility at 35 EFPY. GGNS has implemented the BWRVIP-augmented inspection program for RVI components. The licensee specified that the following inspection programs were to be used to manage the effects of IASCC:

- Core Plate: BWRVIP-25, "BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guidelines," December 1996 (Reference 70);

- Top Guide: BWRVIP-183, "BWR Vessel and Internals Project, Top Guide Grid Beam Inspection and Flaw Evaluation Guidelines," December 2007 (Reference 71); and

- Core Shroud: BWRVIP-76, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," January 2000 (Reference 72).

Top guide inspections requirements are specified in BWRVIP-26, "BWR Top Guide Inspection and Flaw Evaluation Guidelines," November 2004 (Reference 73), but the NRC staff has previously noted that BWRVIP-26 is insufficient to address the potential for cracking multiple top guide beams. By letter dated February 23, 2011 (Reference 5), in response to an NRC staff RAI dated January 31, 2011 (Reference 67), GGNS confirmed that BWRVIP-183 has been implemented providing sufficient inspection to address this issue and noted that top guide grid cracking has not been observed in inspections conducted to date. In addition to the inspections outlined above, GGNS utilizes hydrogen water chemistry application to mitigate the potential for IGSCC and IASCC in RVI components. Water chemistry conditions are also maintained consistent with the Electric Power Research Institute (EPRI) and established industry guidelines, specifically BWRVIP-190, "BWR Water Chemistry Guidelines," 2008 Revision (Reference 74). In addition, noble metal chemical addition was implemented at GGNS in 2010 and is used in conjunction with hydrogen water chemistry.

The licensee concluded that the peak neutron fluence increase experienced by the RVI components as a result of the EPU does not represent a significant increase in the potential for IASCC. The licensee further concluded that the current inspection programs for the RVI components at GGNS are adequate to manage any potential service-induced degradation under EPU conditions.

The NRC staff concludes that the licensee performed an adequate assessment of the RVI components under EPU conditions and that the licensee's implementation of the BWRVIP programs for inspection and flaw evaluation of the RVI components will ensure that the effects of aging are adequately managed under EPU conditions at GGNS. Implementation of the inspection program described above assures the prompt identification of any degradation of RVI components after implementation of the EPU, and water chemistry additions help mitigate potential IGSCC and IASCC in RVI components. The NRC staff concludes that the licensee's continued adherence to BWRVIP guidance, in addition to the mitigating programs, will continue to maintain an acceptable course of action for managing the susceptibility to degradation in the GGNS RVI components under EPU conditions.

Conclusion

The NRC staff concludes that the licensee has demonstrated that the RVI 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 concludes that the proposed EPU is acceptable with respect to the structural integrity of the RVI components.

2.1.4 Reactor Coolant Pressure Boundary Materials

Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff's review of RCPB materials covered their specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. The NRC's acceptance criteria for RCPB materials are based on (1) 10 CFR 50.55a, "Codes and standards," 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; (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, including loss-of-coolant accidents; (3) 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 abnormal leakage, of rapidly propagating failure, and of gross rupture; (4) GDC 31, "Fracture prevention of reactor coolant pressure boundary," which requires that the RCPB be designed with sufficient margin to assure that, when stressed under operating, maintenance, testing, and postulated accident conditions, the boundary behaves in a non-brittle manner and that the probability of a rapidly propagating fracture is minimized; and (5) Appendix G, "Fracture Toughness Requirements," to 10 CFR Part 50, which specifies fracture toughness requirements for ferritic components of the RCPB. Specific review criteria are contained in SRP Section 5.2.3, "Reactor Coolant Pressure Boundary Materials" (Reference 62), and other guidance provided in Matrix 1 of RS-001 (Reference 54). Additional review guidance for IGSCC is contained in NRC Generic Letter (GL) 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," dated January 25, 1988 (Reference 75), and NUREG-0313, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," dated August 12, 1977 (Reference 76), as modified by BWRVIP 75-A, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules," October 1999 (Reference 77). Additional review guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from the NRC to the Nuclear Energy Institute (NEI), dated May 19, 2000 (Reference 78).

Technical Evaluation

This technical evaluation considered the effect of the changes in plant operating conditions due to the proposed extended power uprate on identified and potential modes of degradation to the materials of construction of the RCPB (in this case, piping and nozzles). Degradation modes are considered generically and may or may not specifically apply to the licensee. Changes in operating conditions are specific to the plant. For the purposes of this evaluation, identified modes of degradation are those described in the NUREG-1801, Revision 2, "Generic Aging Lesson Learned (GALL) Report – Final Report," December 2010 (Reference 79). These include IGSCC of stainless steel, thermal aging of stainless steel, and irradiation effects including cracking of all materials. While flow-accelerated corrosion and fatigue meet the current definition of "identified" degradation modes, they are not addressed here but are considered specifically elsewhere in this SE. "Potential" modes of degradation are generally not considered in the GALL Report because the degradation mode is less common or the presence of the material is less likely. Potential modes of degradation, which will be considered here, include IGSCC of nickel alloys, transgranular cracking of stainless steel, and loss of material (general corrosion) of stainless steel and nickel alloys. Current plant operating conditions as well as proposed operating conditions following the EPU are contained in Table 1-2 of the PUSAR (Reference 57). This table indicates that as a result of the EPU there will be: a) no change in system pressure (i.e., pressure will remain at 1040 pounds per square inch (psi) following the uprate); b) no change in maximum system temperature (i.e., the maximum temperature in the system will remain at 549.4 °F following the uprate); and c) a significant change in the flow rate through the system (i.e., following the uprate steam flow will increase to 18.968 millions of pounds per hour (Mlb/hr) from 16.774 Mlb/hr). On page 2-8 of the EPU LAR, the licensee stated that as a result of the EPU there will be "insignificant change to the temperature and flow conditions for portions of the RCPB piping." The NRC staff acknowledges the concept that while peak temperatures in the system do not change, changes in flow rate will cause minor changes in downstream temperatures. The significance of those changes will be considered in the paragraphs below. By electronic mail dated September 12, 2011, the licensee clarified that the "insignificant" temperature changes were reductions in temperature "on the order of 0.2 to 2.0 degrees" (Reference 80).

Identified Modes of Degradation - IGSCC of Stainless Steel

Both initiation and growth of IGSCC are thermally dependent processes. As temperature increases, the time to initiation decreases and crack-growth rate increases. The NRC is unaware of any data which would indicate that the occurrence of IGSCC in rapidly flowing systems is a function of the flow rate. Cracking may be a function of flow rate under essentially stagnant conditions.

The occurrence of IGSCC in stainless steel material is well documented and has been the subject of numerous NRC and industry publications. Reasonable assurance that stainless steel components in the RCPB will not fail to meet their intended safety function due to IGSCC is provided through an inspection program contained in the ASME Code, Section XI and augmented by BWRVIP 75-A. This inspection program depends on the precise materials of construction of the component under consideration, whether crack-mitigation techniques have been employed and whether normal or hydrogen water chemistry is in use. System temperature is not a criterion which is considered in the inspection program.

Given that system temperature is not a variable considered in ASME Code, Section XI/ BWRVIP 75-A for establishing inspection frequency, and given that the inspection intervals established in ASME Code, Section XI/BWRVIP 75-A have been effective in providing reasonable assurance that the intended function of RCPB will be maintained, the NRC staff concludes that the inspection program contained in ASME Code, Section XI/BWRVIP 75-A is effective for the maximum system temperature which exists at the plant prior to the EPU. Given that the maximum system temperature will not increase as a result of the EPU, the NRC staff concludes that the inspection program outlined in ASME Code, Section XI/BWRVIP 75-A will be adequate following the implementation of the uprate. Given that the inspection program contained in ASME Code, Section XI/BWRVIP 75-A is adequate for peak system temperatures, it is also adequate for all lower temperatures because cracks will initiate and grow more slowly under lower temperature conditions. The NRC staff has no concerns about the "insignificant variations in temperature" to which the licensee refers, whether positive or negative, because the maximum temperature associated with these variations must still be less than the maximum system temperature. Therefore, the necessary inspection interval is expected to be bounded by the intervals contained in ASME Code, Section XI/BWRVIP 75-A. The licensee has added additional conservatism to its inspection program by following the more rigorous inspection program identified in BWRVIP 75-A for use with normal water chemistry beyond the fact that the plant employs hydrogen water chemistry.

Identified Modes of Degradation - Thermal Aging of Stainless Steel

Some cast austenitic stainless steels are subject to thermal aging. Thermal aging manifests itself as an increase in hardness and yield strength and a decrease in ductility and toughness. The degree of aging is a function of the chemistry of the steel and the process by which it was cast. The rate of degradation is a function of the operating temperature of the material.

Given that the licensee has not indicated that cast stainless steel components will be replaced as a result of the EPU and that the changes to the operating environment caused by the EPU do not affect either the rate (no temperature change) or the extent (no change in the metallurgical chemistry of the component) of thermal aging, the NRC staff has no concerns regarding this material degradation mode as a result of the EPU.

Identified Modes of Degradation - Irradiation Effects, Including Cracking, of all Materials

Irradiation effects, including IASCC, swelling, and embrittlement are possible in all materials used in the RCPB. The threshold for IASCC is generally considered to be approximately 5×10^{20} n/cm^2. The licensee indicated that, as a result of the EPU, there would be some increase in fluence, particularly in the beltline region. The licensee stated that in the RCPB piping, despite the increase as a result of the EPU, the total fluence would remain well below the threshold value. Based on the above, the NRC staff has no concern regarding this material degradation mode as a result of the EPU.

Potential Modes of Degradation - IGSCC of Nickel Alloys

Although far less common than IGSCC of stainless steels, IGSCC of nickel alloys is well documented. Just as in the case of IGSCC of stainless steels, IGSCC of nickel alloys is temperature sensitive. Increases in temperature decrease the time to crack initiation and increase the crack-growth rate. Also, in a manner similar to stainless steel, inspection programs (ASME Code, Section XI and BWRVIP 75-A) for nickel alloy components and welds have been effective in providing reasonable assurance that these welds and components will maintain their intended safety functions at the maximum temperature within the system prior to the EPU. Given that there is no increase in maximum system temperature associated with the EPU, the new operating conditions remain bounded by the existing conditions, upon which the current, successful, inspection program is based. As was the case with stainless steel components, the NRC staff has no concern regarding minor temperature variation between existing and EPU conditions, irrespective of whether these variations are positive or negative, because the temperatures must be less than the maximum system temperature and, therefore, bounded by the conditions upon which current inspections are based.

Potential Modes of Degradation - Transgranular Cracking of Stainless Steel

Transgranular stress-corrosion cracking is a possible degradation mechanism for austenitic stainless steels when exposed to environments containing halogens, such as chlorides, and dissolved oxygen. The NRC staff notes that EPRI water chemistry guidelines (BWRVIP-190, Reference 74) recommend that the levels of oxygen and halogens be maintained at levels which will not result in transgranular cracking. Based on the licensee's current adherence to the

EPRI water chemistry guidelines and the lack of any proposed modification to the plant's water chemistry as a result of the EPU, the NRC staff has no concern regarding this material degradation mode as a result of the EPU.

Potential Modes of Degradation - Loss of Material (General Corrosion) Stainless Steel and Nickel Alloys

General corrosion is often, but not always, a positive function of temperature (i.e., corrosion rates increase as temperature increases). General corrosion is also, under certain circumstances, a function of flow rate (i.e., when the rate of corrosion is limited by mass transport). In the present case, the corrosion rates of stainless steels and nickel alloys when exposed to high-purity reactor coolant are sufficiently low so as not to require consideration. Changes in environment associated with the EPU are not sufficient to cause these materials to corrode at an appreciable rate.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of RCPB materials. The NRC staff further concludes that the licensee has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed EPU and will continue to meet the requirements of GDCs 1, 4, 14, and 31; Appendix G to 10 CFR Part 50; and 10 CFR 50.55a. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to RCPB materials.

2.1.5 Protective Coating Systems (Paints) - Organic Materials

Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and radionuclide contamination, and coatings also provide wear protection during plant operation and maintenance activities. Considering radiation and pressure, the NRC staff's review covered Service Level 1 protective coating systems used inside the containment for their suitability and stability under design basis loss-of-coolant accident (DBLOCA) conditions. The NRC's acceptance criteria for protective coating systems are based on (1) Appendix B, "Quality Assurance Criteria For Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50, which covers quality assurance requirements for the design, fabrication, and construction of safety-related SSCs; and (2) NRC Regulatory Guide (RG) 1.54, Revision 2, "Service Level I, II. and III Protective Coatings Applied to Nuclear Power Plants," October 2010 (Reference 81), which covers application and performance monitoring of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2, "Protective Coating Systems (Paints) – Organic Materials Review Responsibilities" (Reference 62).

Technical Evaluation

The licensee stated that the Service Level 1 protective coatings used at GGNS in the drywell (i.e., primary containment) were qualified per American National Standards Institute (ANSI) Standard ANSI N101.2-1972, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," to a radiation level of 1.4×10^9 rads and a temperature of 340 °F. The licensee stated that the peak temperature during an accident under EPU conditions was determined to be <340 °F. It was further indicated that the EPU peak temperature ignores a short initial 1-second transient to 347 °F, and that this transient would have an insignificant effect on the coating temperatures. In addition, the licensee indicated that the coatings in the drywell were qualified to a peak pressure of 70 pounds per square inch gage (psig). The peak pressure under EPU conditions for a DBLOCA was determined to be 26.7 psig. The licensee stated that the Service Level 1 protective coatings qualification levels are bounding of EPU accident conditions.

The licensee stated that the protective coatings in the containment (i.e., secondary containment or reactor building) remain bounding of EPU accident conditions. Because failure of protective coatings used in secondary containment do not adversely affect the operation of post-accident fluid systems (i.e., ECCS), it is not part of the scope of the EPU review. As such, the NRC staff did not review the acceptability of protective coatings used in the secondary containment. In addition, the licensee stated that the suppression pool (i.e., wetwell) is stainless-steel-lined, reinforced concrete, and does not have Service Level 1 protective coating. The licensee indicated that the suppression pool is not part of the protective coatings program. The NRC staff reviewed the GGNS design and licensing bases to confirm that the suppression pool does not have protective coatings. The NRC staff concludes that the exclusion of the suppression pool from the Service Level 1 protective coatings program is acceptable because the suppression pool does not have protective coatings.

The licensee stated that the protective coatings inside the primary containment are monitored and maintained according to ANSI 101.2-1972, ANSI N101.4-1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities," ANSI N5.12-1974, "Protective Coatings (Paints) for the Nuclear Industry," RG 1.54, Revision 0, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," May 1973 (Reference 82), and ANSI/ASME NQA-1-1983, "Quality Assurance Program Requirements for Nuclear Power Plants." The licensee also stated that the coating condition assessment of Service Level 1 coatings inside the primary containment are conducted every refueling outage. The program monitors for coating conditions, such as, blistering, cracking, peeling, loose rust, and physical/mechanical damage.

The licensee stated that when localized degradation of a coating is identified, the affected area is evaluated and scheduled for repair, replacement, or removal, as needed. The NRC staff concludes that this is acceptable because the repair, replacement, or removal activities ensure that the coatings potentially affected during a DBLOCA will experience minimum detachment; therefore, the ECCS suction strainers will not be impacted adversely by coating debris.

After reviewing the licensee's coatings evaluation, the NRC staff concluded that the coating qualifications remain bounding for peak pressure and peak radiation under EPU conditions. The NRC staff concludes that the coatings peak pressure and peak radiation qualifications are acceptable. However, the NRC staff reviewed the coatings peak temperature qualification under EPU conditions and determined that more information was needed to complete its review. By electronic mail dated February 8, 2011 (Reference 83), the NRC staff issued an RAI in which it requested that the licensee discuss how the coatings testing qualification remains bounding for the EPU 1-second transient peak temperature of 347 °F. In its response to the RAI dated March 9, 2011 (Reference 8), the licensee indicated that the 347 °F 1-second transient is a brief occurrence in the primary containment. This transient happens during the first second of the accident, then drops below and stays below the 340 °F design temperature.

In addition, the licensee stated that the coatings in containment do not instantaneously heat to the temperature of the drywell environment; rather, the temperature response of the coatings is based on convective heat transfer properties and thermal capacity. As such, the licensee stated that the exposure to a 1-second spike of elevated temperature is not significantly long enough to heat the protective coatings beyond their initial temperature condition (i.e., ≤135 °F per the GGNS TSs). The licensee stated that the ultimate peak temperature of the coatings themselves would remain below the qualification temperature of 340 °F, in conformance to design requirements.

The NRC staff reviewed the licensee's response and concludes that the Service Level 1 protective coatings will remain suitable and stable under EPU DBLOCA conditions because the peak temperature of the protective coatings will remain below the coating test qualification peak temperature of 340 °F. The NRC staff concludes that the licensee has demonstrated that the protective coating systems remain acceptable for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on protective coating systems. The NRC staff concludes that the licensee has appropriately addressed the impact of changes in conditions following a DBLOCA and their effects on the protective coatings. The NRC staff further concludes that the licensee has demonstrated that the protective coatings will continue to be acceptable following implementation of the proposed EPU. Specifically, the protective coatings will continue to meet the requirements of 10 CFR Part 50, Appendix B and RG 1.54, Revision 2. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to protective coatings systems.

2.1.6 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 highly resistant to FAC, and FAC is significantly reduced in components containing even small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on flow velocity, component geometry, fluid temperature, steam quality, oxygen content, and pH. During plant operation, it is difficult to maintain all of these parameters in a regime that minimizes FAC; therefore, loss of material by FAC can occur. The NRC staff reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee's FAC program to predict the rate of material loss so that repair or replacement of damaged components could be made before reaching a critical thickness. The licensee's FAC program consists of predicting material loss by the use of the CHECWORKS™ Steam Feedwater Application (SFA) computer code, visual inspection, and volumetric examination of the affected components. The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

Technical Evaluation

The licensee stated that the EPU implementation at GGNS will affect a number of water and steam system flow rates, temperatures, and enthalpies (e.g., increased feedwater and increased steam flow). The associated changes in these parameters affect material and system susceptibility to FAC and FAC wear rates. The licensee stated that some systems (i.e., lines) will experience accelerated rates of FAC wear, while others will have reduced rates. The licensee indicated that lines that were previously not susceptible to FAC will remain non-susceptible to FAC under EPU conditions. The licensee determined that the FAC program is adequate to manage any potential effects of the EPU.

The licensee stated that the FAC program is based on the following documents: 1) NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," dated July 9, 1987 (Reference 84); 2) NRC Generic Letter (GL) 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," dated May 2, 1989 (Reference 85), and 3) the guidelines in the EPRI Report NSAC-202L-R3, "Recommendation for an Effective Flow-Accelerated Corrosion Program," May 2006 (Reference 86). In following the EPRI NSAC-202L guidance document to perform FAC evaluations, the licensee stated that it is able to determine how long components will remain above minimum-allowable wall thickness and to determine when replacement is necessary. Additionally, the licensee is able to predict the minimum wall thickness at the end of each operating cycle. The evaluation also shows the remaining service life of the component and the next scheduled inspection outage.

The licensee stated that the FAC program monitors all FAC-susceptible small and large bore piping systems to ensure that structural integrity and functionality are maintained. The FAC-susceptible piping is divided into two categories: lines that meet the requirements to be modeled using EPRI CHECWORKS™ SFA, and those that do not. The licensee stated that GGNS uses CHECWORKS™ SFA, in conjunction with actual measurements, to predict FAC wear rates and remaining service life for components in single-phase and two-phase systems.

Systems that do not meet the minimum requirements for modeling and analysis by CHECWORKS™ SFA are referred to by the licensee as "Susceptible-Not Modeled [S-NM]." The licensee uses industry and plant-specific operating experience, and engineering judgment to determine which S-NM systems should be selected for inspection. Engineering judgment is used to ensure that the most representative sample of items (e.g., S-NM components) with the highest probability of damage will be examined and evaluated.

The licensee indicated that the implementation of the EPU will result in changes to several variables that may directly influence FAC wear rates. It was indicated that the parameters that are affected include operating temperature, steam quality, and velocity. The licensee indicated that the oxygen concentration is not expected to significantly change. The licensee stated that the CHECWORKS™ SFA model was updated based on the EPU heat balance diagram to account for the changes due to the EPU conditions. Furthermore, based on the changes in predicted wear rates, actual component thickness, operating time since last examination, and design margin, the licensee stated that there will be an increase in the number of FAC inspections performed on both the CHECWORKS™ SFA-model and S-NM piping over the next several RFOs to better understand and characterize the effect of the power uprate. The data will be used to calibrate the CHECWORKS™ SFA model and susceptibility rankings for S-NM piping. Updating the predictive computer code and continuing to gather operating experience will ensure that the FAC-susceptible components are inspected or replaced prior to reaching code minimum wall thickness.

The licensee provided a sample list of most susceptible components for which wall thinning was predicted and measured. In order to determine whether the CHECWORKS™ SFA FAC predictions are conservative, the NRC staff reviewed the changes to each component in the sample list provided by the licensee. These components have the highest predicted wear rates under the current rated thermal power (RTP) (i.e., prior to the EPU). The table shows that in 115 of 117 cases, the measured thickness from inspection was greater than the CHECWORKS™ SFA model predicted thickness. Therefore, the results show that the CHECWORKS™ SFA model conservatively predicts the component thickness. Although 2 of the 117 cases had actual measurement thicknesses less than the predicted thicknesses, the licensee indicated that the actual measurements were greater than their minimum-allowable thicknesses. In addition, the licensee stated that the FAC program will be updated to include EPU system parameters to ensure that required changes to component inspection and replacement schedules are made prior to EPU implementation. The NRC staff concludes that this is acceptable because the CHECWORKS™ SFA model conservatively predicts the component thickness when compared to the actual thickness measurement and the FAC program will be updated to include EPU system parameters to adequately determine component inspection and replacement schedules.

The NRC staff has reviewed the licensee's evaluation and verified that the applicable regulatory guidance was followed. The licensee has demonstrated that the FAC program is adequate for managing the potential effects on systems and components. The NRC staff concludes that the FAC program is adequate in predicting the rate of material loss. Thus, repair or replacement of damaged components can be made before they reach a critical thickness.

Conclusion

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

2.1.7 Reactor Water Cleanup System

Regulatory Evaluation

The reactor water cleanup (RWCU) system provides a means for maintaining reactor water quality by filtration and ion exchange, and provides a path for removal of reactor coolant when necessary. In addition, maintaining RWCU system integrity is important because portions of the system comprise the RCPB. The NRC staff's review of the RWCU includes component design parameters for flow, temperature, pressure, heat-removal capability, and impurity-removal capability; also, the review includes instrumentation and process controls for proper system operation and isolation. The review consists of evaluating the adequacy of the plant's TSs as it relates to the RWCU system, under proposed EPU conditions. The NRC's acceptance criteria for the RWCU system are based on the following: (1) GDC 14, "Reactor coolant pressure boundary," which requires that the RCPB be designed, fabricated, erected, and tested to have an extremely low probability of rapidly propagating fracture; (2) GDC 60, "Control of releases of radioactive materials to the environment," which requires that the plant design include means to control the release of radioactive effluents; and (3) GDC 61, "Fuel storage and handling and radioactivity control," which requires systems that contain radioactivity to be designed with appropriate confinement. Specific review criteria are contained in SRP Section 5.4.8, "Reactor Water Cleanup System (BWR)" (Reference 62).

Technical Evaluation

The licensee stated that the RWCU system is a normally operated system with no safety-related functions other than containment isolation. The system is designed to remove solid and dissolved impurities from recirculated reactor coolant, thereby reducing the concentration of radioactive and corrosive species in the RCS. It was indicated that the increase in feedwater flow under EPU conditions may have a minor effect on the RWCU system.

Under EPU conditions, the licensee stated that the RWCU system will operate at a slightly decreased temperature (from 532.7 °F to 530.8 °F). The system currently operates at flow rates slightly higher than the design flow. The licensee indicated that the nominal operating flow rates will not be changing under EPU conditions. Although the RWCU system flow is usually selected to be 1 percent of feedwater flow, and the feedwater system flow will increase under EPU conditions, the licensee stated that the RWCU flow will remain at its current rate at the EPU RTP level. It was indicated that the existing RWCU system flow and the flow analyzed for the EPU are within the BWR operational history and have additional margin. The evaluations performed by the licensee considered water chemistry, heat exchanger performance, pump performance, flow control valve capability, and filter/demineralizer performance. The licensee stated that all aspects of performance were found to be within the design of the RWCU system at the analyzed flow at EPU conditions.

The licensee identified the following conclusions as a result of the RWCU system analysis for EPU conditions:

1. There is a negligible heat load effect.

2. A small increase in filter/demineralizer backwash frequency occurs, but this is within the capacity of the radwaste system.

3. The changes in operating system conditions result from a decrease in inlet temperature and increase in FW [feedwater] system operating pressure.

4. The RWCU system filter/demineralizer control valves operate in a more open position to compensate for the increased FW system pressure.

5. No changes to instrumentation are required, and setpoint changes are not required due to the negligible system process parameter changes.

By evaluating previous operating experience, the licensee has identified four parameters that may be affected by EPU conditions. The parameters affected are reactor water iron, feedwater iron, sulfates, and chloride concentrations. The parameters increase in concentration under EPU conditions.

The licensee indicated that the reactor water-iron concentration increases from 42.74 parts per billion (ppb) to 48.29 ppb for the as-operated case. The licensee indicated that the increase in iron concentration is insignificant, and does not affect RWCU system performance. The increased reactor water-iron concentration is expressed relative to the current levels of feedwater iron concentration. In addition, the licensee stated that GGNS is installing a condensate full flow filtration to reduce the feedwater iron concentration below 1 ppb (currently, levels are at 4.8 ppb), which is expected to significantly lower reactor water-iron concentration. The licensee stated that the average level of sulfates will increase from 1.393 ppb to 1.573 ppb for the nominal as-operated case. Despite the increase, it was indicated that the average level of sulfates will remain below the administrative limit of 5.0 ppb. The licensee stated that the average level of chlorides will increase from 0.108 ppb to 0.122 ppb for the nominal as-operated case. The licensee indicated that the increased concentration of chloride will remain below the administrative limit of 5.0 ppb for chlorides. The licensee also reported that the calculated reactor water conductivity will increase from 0.077 micro Siemens per centimeter (μS/cm) to 0.080 μS/cm because of the increase in feedwater flow. The licensee reported that the water conductivity will remain below the administrative limit of 0.30 μS/cm. Furthermore, the licensee stated that the water conductivity limits will not change under EPU conditions. The NRC staff reviewed the effects of the EPU on chemistry values and concludes that the changes are acceptable because the values will remain below the administrative limits or have minimum impact on RWCU system performance under EPU conditions.

The licensee stated that the RWCU system can perform adequately at EPU RTP with the original RWCU system flow. Although there are small changes to the RWCU system operating conditions, the licensee indicated that the system has sufficient capacity to respond to EPU conditions and maintain the chemistry parameters within administrative limits.

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

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the RWCU system and concludes that the licensee has adequately addressed changes in temperature, impurity and chemistry, and their effects on the RWCU system. The NRC staff further concludes that the licensee has demonstrated that the RWCU system will continue to be acceptable and will continue to meet the requirements of GDCs 14, 60, and 61. Based on the above, the NRC staff concludes that the proposed EPU is acceptable with respect to the RWCU system.

2.1.8 Pressurized Temperature Limits Report (PTLR)

Regulatory Evaluation

The NRC has established requirements in 10 CFR Part 50 to protect the integrity of the RCPB in nuclear power plants. The NRC staff evaluates the acceptability of a facility's proposed P-T limits based on the following NRC regulations and guidance: Appendix G, "Fracture Toughness Requirements," to 10 CFR Part 50; Appendix H, "Reactor Vessel Material Surveillance Program Requirements," to 10 CFR Part 50; NRC Regulatory Guide (RG) 1.99, Revision 2 (Reference 66); NRC Generic Letter (GL) 92-01, Revision 1, "Reactor Vessel Structural Integrity," dated March 6, 1992 (Reference 87); GL 92-01, Revision 1, Supplement 1, "Reactor Vessel Structural Integrity," dated May 19, 1995 (Reference 88); and SRP Section 5.3.2, "Pressure-Temperature Limits, Upper-Shelf Energy, and Pressurized Thermal Shock" (Reference 62). Appendix G to 10 CFR Part 50 requires that facility P-T limits for the RPV be at least as conservative as those obtained by applying the linear elastic fracture mechanics methodology of Appendix G to Section XI of the ASME Code. Appendix H to 10 CFR Part 50 establishes requirements related to facility RPV material surveillance programs. RG 1.99, Revision 2, contains methodologies for determining the increase in transition temperature and the decrease in upper-shelf energy (USE) resulting from neutron radiation.

GL 92-01, Revision 1, requested that licensees submit the RPV data for their plants to the NRC staff for review, and GL 92-01, Revision 1, Supplement 1, requested that licensees provide and assess data from other licensees that could affect their RPV integrity evaluations. SRP Section 5.3.2 provides an acceptable method for determining the P-T limits for ferritic materials in the beltline of the RPV based on the ASME Code, Appendix G methodology.

The most recent version of Appendix G to Section XI of the ASME Code which has been endorsed in 10 CFR 50.55a, "Codes and standards," and therefore by reference in 10 CFR Part 50, Appendix G, is the 2004 Edition of the ASME Code. This edition of Appendix G to Section XI of the ASME Code incorporates the provisions of ASME Code Case N-588, "Attenuation to Reference Flaw Orientation of Appendix G for Circumferential Welds in Reactor Vessels," and ASME Code Case N-640, "Alternative Reference Fracture Toughness for Development of P-T Limit Curves." Additionally, Appendix G to 10 CFR Part 50 imposes minimum head-flange temperatures when system pressure is at or above 20 percent of the preservice hydrostatic test pressure.

NRC GL 96-03, "Relocation of the Pressure Temperature Limit Curves and Low Temperature Overpressure Protection System Limits," dated January 31, 1996 (Reference 89), establishes the information which must be included in an acceptable PTLR methodology and in an acceptable PTLR. The PTLR also needs to comply with Technical Specification Task Force (TSTF) Improved Standard TS (ISTS) Change Traveler TSTF-419-A, "PTLR Definition and References in ISTS 5.6.6, RCS PTLR," which documents revised guidance for a plant's PTLR. Since this LAR requested the initial implementation of the PTLR for the GGNS unit, the NRC staff's review focused on both the implementation of the GGNS PTLR and the appropriate application of the NEDC-33178-A, "General Electric Methodology for Development of Reactor Pressure Vessel Pressure-Temperature Curves," dated June 30, 2009 (Reference 90), henceforth "the GE methodology," to generate the proposed P-T limits. The related neutron fluence calculation was reviewed by the NRC staff.

Technical Evaluation

Licensee's Evaluation

The revised P-T limits are based on application of the NEDC-33178-A GE methodology to GGNS. NEDC-33178-A provides the approved generic GE methodology for generating P-T limits based on the plant-specific adjusted reference temperature (ART). The GE methodology provides beltline and generic upper vessel and bottom head P-T limit curves that are shifted by the plant-specific ART, as well as guidance on the application of the ASME Code, Appendix G and 10 CFR Part 50, Appendix G.

For the RPV beltline material, the licensee identified the plate A1224-1 as the limiting beltline material for GGNS based on integrated surveillance program (ISP) data reported in BWRVIP-135, "BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Data Source Book and Plant Evaluations," 2004 (Reference 91). ART values at 35 EFPY are also provided for the bottom head and upper vessel, although the limiting materials are not identified explicitly. The licensee noted that the N12 water level instrument nozzle was evaluated and that it was determined that the P-T limits for the instrument nozzle was not limiting; rather, the limiting material at that location was the adjoining shell ring #2. The parameters used to determining the licensee's ART values for the limiting materials at the one-quarter of the RPV wall thickness (1/4T) location for 35 EFPY are shown in on page 25 of Attachment 7 of the EPU LAR (Reference 1). Corresponding parameters at three-quarters of the RPV wall thickness (3/4T) are not provided in the attachments because the licensee stated that the P-T limit curves based on the cooldown transient (the relevant critical location is at the 1/4T) are more conservative than the P-T limit curves based on the heatup transient (the relevant critical location is at the 3/4T).

The licensee's proposed PTLR is provided in Attachment 7 of the EPU LAR, "Pressure and Temperature Limits Report (PTLR) up to 35 Effective Full-Power Years (EFPY), Revision 0" (Reference 92). Composite P-T limit Curves A, B, and C are summarized in the proposed PTLR in Figure 1, "Composite P-T Curves Effective for up to 35 EFPY [Without Uncertainty for Instrumentation Errors]," and Table 1, "Tabulation of Curves – 35 EFPY," and are based on application of the GE methodology. The licensee notes that "the P-T curves are beltline (A1224-1 plate) limited above 1330 psig for Curve A for 35 EFPY and are Upper Vessel limited above 312.5 psig for Curve B for 35 EFPY."

NRC Staff Evaluation

PTLR Implementation

The licensee utilized the GE methodology to generate its P-T limits. The GE methodology was approved as a reference for use in generating PTLRs.

As noted above, GL 96-03 requires that the licensee evaluate seven technical criteria to demonstrate the acceptability of its PTLR. The NRC staff examined the proposed PTLR and determined that it was developed from the Template PTLR found in the GE methodology report and meets the seven technical criteria:

(1) The PTLR methodology describes the transport calculation methods including computer codes and formula used to calculate neutron fluencies.

The GGNS PTLR indicated that the neutron fluence was calculated per the NRC-approved methodology NEDC-32983-A, "Licensing Topical Report, General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation," January 2006 (Reference 93). This approved report documents the transport calculation methods including computer codes and formula used to calculate neutron fluencies. Hence, the first criterion is met.

(2) The PTLR methodology describes the surveillance program.

The GGNS PTLR indicated that the GGNS has participated in the approved BWRVIP ISP, which meets the requirements of 10 CFR Part 50, Appendix H. Hence, the second criterion is met.

(3) The PTLR methodology describes how the low temperature overpressure protection system limits are calculated applying system/thermal hydraulics and fracture mechanics.

This is not applicable to BWRs, and the GGNS unit is a BWR.

(4) The PTLR methodology describes the method for calculating the ART values using RG 1.99, Revision 2.

The GGNS PTLR indicated that RG 1.99, Revision 2, provides the methods for determining the ARTs for the beltline materials, with their chemistry factors determined by surveillance data information from the BWRVIP ISP. Hence, the fourth criterion is met.

(5) The PTLR methodology describes the application of fracture mechanics in the construction of P-T limits based on ASME Code, Section XI, Appendix G, and the SRP.

On page 2 of the PTLR, it is stated that the P-T limits were calculated in accordance with the GE methodology. This description is sufficient as the GE methodology report was reviewed and found to meet the fifth criterion. Hence, the fifth criterion is met.

(6) The PTLR methodology describes how the minimum temperature requirements in Appendix G to 10 CFR Part 50 are applied to P-T limits for boltup temperature and hydrotest temperature.

Again, referencing the GE methodology is sufficient because the report contains detailed information regarding the minimum temperature requirements for boltup temperature and hydrotest temperature. The NRC staff reviewed and approved the GE methodology under the sixth criterion. Hence, the sixth criterion is met.

(7) The PTLR methodology describes how the data from multiple surveillance capsules are used in the ART calculation.

Again, referencing the GE methodology is sufficient because the report contains detailed information regarding this criteria in the GE methodology Appendix I. The NRC staff reviewed and approved the GE methodology under the seventh criterion. Hence, the seventh criterion is met.

Based on the above, the NRC staff concludes that implementation of the GGNS PTLR is acceptable.

P-T Limits

The proposed P-T limits are a composite of the RPV beltline, the bottom head, and the upper vessel curves. Independent P-T curves generated by the NRC staff are consistent with P-T curves provided by the licensee, including (1) Bottom Head Curves A and B using the GE methodology, (2) Beltline Curve A above ~1360 psig using the ASME Code, Appendix G, (3) Upper Vessel Curve C below 312 psig using the GE methodology, and (4) the requirements of 10 CFR Part 50, Appendix G.

To evaluate the proposed GGNS RPV beltline P-T limits, the NRC staff first examined and confirmed the licensee's selection of ISP plate A1224-1 as the limiting beltline material. For the GGNS beltline materials, the NRC staff concludes that the initial RT_{NDT}, copper (Cu), and nickel (Ni) values are in agreement with the information in the NRC's Reactor Vessel Integrity Database (RVID). Using data from RVID and the procedure outlined in Position 1 of RG 1.99, Revision 2, the NRC staff identified the limiting GGNS beltline materials at 35 EFPY as shell ring 2 heat A1113-1 and shell ring 1 heat C2557-2, both with a calculated ART of 40.7 °F. The licensee reported best-estimate chemistry and ISP data from BWRVIP-135 (Reference 91) in accordance with procedures outlined in BWRVIP-86-A (Reference 64), to ensure the collection of credible chemistry and surveillance data. Best-estimate chemistries from BWRVIP-135 do not significantly differ from RVID and, therefore, the inclusion of best-estimate chemistry does not change the limiting beltline material previously identified by the NRC staff. Using data from the ISP reported in BWRVIP-135, the licensee identified plate A1224-1 with a calculated ART of 42.6 °F as the bounding limiting beltline material from the ISP, more conservative than the 40.7 °F ART calculated by the NRC staff using data from RVID and RG 1.99, Revision 2. The ART evaluation described above is for the RPV 1/4T location, as ART evaluation at the 3/4T location was not conducted by the licensee. This is appropriate because the licensee's approach of using the maximum tensile stress for either heatup or cooldown and applying it at the 1/4T location is equivalent to using the maximum thermal stress intensity factor (K_{IT}) and the minimum fracture toughness (K_{Ic}) in the heatup and cooldown analysis, making the proposed P-T limits bound both the heatup and cooldown curves.

As noted previously, the licensee made use of the GE methodology in generating P-T limits, with Bottom Head P-T Curves A and B and composite P-T limit Curves A, B, and C provided by the licensee. Bottom head curves reported by the licensee are consistent with bottom head curves generated by the NRC staff applying the GE methodology, shifting the approved generic GE bottom head curve by the ART for the limiting material identified. For Curve A, the licensee noted that Appendix G to the ASME Code beltline P-T curves are limiting above 1330 psig. The NRC staff questioned this value in an RAI dated January 31, 2011 (Reference 67), and the licensee confirmed in its RAI response dated February 23, 2011 (Reference 5), that 1360 psig is the correct value and that the notation will be updated. For composite Curve C, the NRC staff concludes that the upper vessel curve generated using the GE methodology limiting below ~312 psig, is consistent with the composite P-T curve provided by the licensee. For all other conditions, the Appendix G to 10 CFR Part 50 requirements for the minimum metal temperature of the closure head flange and vessel flange regions are limiting, serving to explain the distinct vertical lines at constant temperature above ~312 psig in the licensee's proposed P-T limits. When P > 20 percent of the hydrotest pressure (~ 312 psig), the minimum temperature of 100 °F for the pressure test curve, 130 °F for the normal operation/core not critical curve, and 170 °F for the normal operation/core critical curve are derived from adding the RT_{NDT} of 10 °F for the limiting flange material temperature to 90 °F, 120 °F, and 160 °F that were specified in Appendix G to 10 CFR Part 50 for the three operation conditions. The NRC staff also verified that when P ≤ 312 psig, the minimum temperature of 70 °F for the pressure test curve and the normal operation/core not critical curve is more conservative than the RT_{NDT} for the limiting flange material temperature that was specified in 10 CFR Part 50, Appendix G.

The GGNS PTLR (Reference 92) identified nozzle N12 as a beltline water level instrument nozzle and noted that an evaluation was performed on this nozzle that determined it was not a limiting material for the adjoining shell ring. The licensee responded that an evaluation was performed as shown in Appendix J of NEDC-33178-A, and that this analysis demonstrated that the nozzle was bounded by the beltline and upper vessel for Curves A, B, and C. The NRC concludes that this response is acceptable.

Based on the above, the NRC staff determined that the licensee's proposed P-T limits are in accordance with the NEDC-33178-A report and satisfy the requirements of Appendix G to Section XI of the ASME Code and Appendix G to 10 CFR Part 50. Based on the above, the NRC staff concludes that the licensee's proposed P-T limit curves are acceptable for operation of the GGNS RPV valid for 35 EFPY.

Conclusion

Based on the NRC staff's review of the information provided in the licensee's EPU LAR and the February 23, 2011, submittals, the NRC staff concludes that the proposed GGNS PTLR meets GL 96-03 requirements for implementation and, therefore, is approved as part of the GGNS licensing bases.

The NRC staff concludes that the GGNS RPV P-T limits are based on an acceptable methodology documented in the NEDC-33178-A report. The staff performed independent evaluations and verified that the P-T limits were developed appropriately using the NEDC-33178-A methodology, and the proposed P-T limits, valid for 35 EFPYs, satisfy the requirements of Appendix G to Section XI of the ASME Code and Appendix G to 10 CFR Part 50. The NRC staff concludes that the TS revision to reflect the use of this methodology is appropriate.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

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

The NRC staff's specific review and acceptance criteria are based on SRP Section 3.6.2, "Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping" (Reference 62), and on the CLB requirements at GGNS related to the postulation of pipe rupture locations and associated dynamic effects. The GGNS criteria related to the postulation of pipe rupture and crack locations are located in Section 3.6 of the GGNS UFSAR and are based on the criteria contained in Branch Technical Position (BTP) MEB 3-1, Revision 0, which is contained within SRP Section 3.6.2, Revision 0. Additionally, the CLB requirements related to the dynamic effects loadings imposed on SSCs important to safety at GGNS are based on the criteria found in GGNS UFSAR Section 3.6A.2.2. The NRC staff's review also considered the guidance provided in Sections 10.1 and 10.2 of the CLTR (Reference 55), which contain NRC staff-approved methodologies for evaluating the effects of EPU implementation on the existing high-energy line break (HELB) and moderate energy line break (MELB) analyses at BWRs, respectively. Additionally, the NRC staff considered the guidance found in Section 3.5, "Piping Evaluation," of the CLTR, given that HELBs and MELBs are inherently coupled to the guidance provided in the CLTR to determine stresses in piping systems resulting from EPU implementation. The SE enclosed with the CLTR documents the NRC staff's review and approval of these methodologies, including any limitations on the use of the CLTR.

Technical Evaluation

As part of the proposed EPU implementation at GGNS, the licensee evaluated the pipe rupture analyses at GGNS to ensure that SSCs important to safety will continue to be adequately protected from the effects of pipe ruptures following EPU implementation. The evaluations performed for EPU effects on the HELB analyses, including dynamic effects evaluations, are documented in Section 2.2.1 of the PUSAR (Reference 57) while the effects of EPU implementation on the MELB analyses are documented in Section 2.5.1.3 of the PUSAR. The licensee stated that the HELB and MELB evaluations performed in support of the proposed EPU implementation were done in accordance with the NRC-approved methodologies outlined in Sections 10.1 and 10.2 of the CLTR, respectively.

2.2.1.1 High-Energy Line Breaks

As indicated in GGNS UFSAR Section 3.6A.2, high-energy piping at GGNS is defined as piping systems or portions of systems in which the maximum operating temperature exceeds 200 degrees Fahrenheit (^{o}F) or the maximum operating pressure exceeds 275 psig during normal plant conditions; these piping systems are identified in GGNS UFSAR Tables 3.6A-14 and 3.6A-15. In Section 2.2.1 of the PUSAR, the licensee identified the following high-energy piping systems inside containment as being affected by the proposed EPU implementation at GGNS: main steam, main steam drains, reactor core isolation cooling (RCIC) steam line, feedwater, main steam vent lines, and main steam safety relief valve (SRV) piping (between the main steam line (MSL) and each SRV). Outside containment, the following high-energy lines were identified by the licensee as being affected by EPU implementation at GGNS: main steam, feedwater, main steam drains, RCIC, residual heat removal (RHR), and reactor water cleanup (RWCU).

The criteria used to determine whether an HELB is required to be postulated at GGNS are located in Section 3.6A.2.1(c) of the GGNS UFSAR. The licensee evaluated the stresses in the affected piping systems (or portions of systems) due to EPU implementation in an effort to determine whether the revised stresses under EPU conditions required the postulation of a new HELB, based on whether the revised stresses exceeded the CLB HELB criteria. The licensee summarized the results of the structural evaluations of the RCPB and balance-of-plant (BOP) piping systems in Tables 2.2-2 through 2.2-6, respectively, of the PUSAR. These tables detail the effects of EPU implementation on the temperature, pressure, flow, and mechanical loadings of the piping systems at GGNS, including the aforementioned high-energy piping affected by EPU implementation, and provide summaries of the results of stresses and fatigue usage factors (as applicable) of piping affected by EPU implementation. Based on the licensee's evaluations summarized in these tables, the NRC staff concludes that the main steam system, including associated branch piping, was the only piping significantly affected by EPU implementation at GGNS. Additional information regarding the licensee's evaluation of the structural integrity of the GGNS piping systems is discussed in SE Section 2.2.2.

The percent increases in the stresses, usage factors, interface loads and thermal displacements, due to EPU implementation, for the Class 1 and Class 2 and 3 main steam system piping were provided in PUSAR Tables 2.2-3a and 2.2-3b, respectively. The licensee applied these percent increases to the applicable American Society of Mechanical Engineers Boiler and Pressure Vessel (ASME Code) stress equations used to structurally qualify the main steam system piping. The application of these percent increases to the applicable stress equations represent the stresses in the main steam system piping at EPU conditions; these are quantitatively summarized in Tables 2.2-4a through 2.2-4l of the PUSAR. As indicated in Section 3.6A.2.1(c) of the GGNS UFSAR, these stress equations also form the bases for the postulation of HELBs at GGNS. The licensee presented a quantitative summary of the main steam system piping stresses at EPU conditions against the applicable HELB postulation criteria in Tables 2.2-4b (MSLs A and D) and 2.2-4d (MSLs B and C) of the PUSAR. In these tables, the licensee demonstrated that the stresses in the limiting nodes in the piping stress analysis continue to remain below the threshold for the postulation of an HELB at EPU conditions. By letter dated February 23, 2011 (Reference 6), in response to an NRC staff RAI dated January 27, 2011 (Reference 94), regarding the absence of two nodes in Table 2.2-4d, which were deemed limiting in separate tables, the licensee provided a complete summary of the results of the revised stresses at all of the limiting nodes in stress analyses for MSLs B and C. Based on the evaluation of the main steam piping stresses against the applicable HELB criteria, the licensee concluded that no new HELBs are required to be postulated at EPU conditions.

2.2.1.2 Dynamic Effects Evaluation

In addition to evaluating the effects of EPU implementation on postulated HELB locations, the licensee also evaluated the consequences of EPU implementation on the dynamic effects associated with HELBs, including pipe whip and jet impingement loads. This evaluation is summarized in Section 2.2.1.2.3 of the PUSAR and includes a methodical overview of the parameters governing dynamic effects loads. The licensee notes that these dynamic effects loads are a function of the pressure and temperature of a high-energy system as well as size the size and orientation of specific HELB locations. Using these parameters, the licensee determined whether EPU implementation resulted in the increase of any dynamic effects loadings on SSCs within the calculated proximity of a postulated HELB. As indicated above, no new HELBs are required to be postulated as part of EPU implementation at GGNS. Therefore, the licensee evaluated the effects of EPU implementation on the existing dynamic effect loadings which are coupled with the existing HELB locations that are currently required to be postulated.

The licensee evaluated the high-energy systems inside and outside of containment to determine whether the parameters associated with dynamic effects loadings were affected by EPU implementation. The licensee stated in the PUSAR that the feedwater system is the only high-energy piping system inside containment experiencing an increase in operating pressure as a result of EPU implementation; Section 2.2.2 of the PUSAR notes that the pressure increase in the feedwater system is slight, as shown in the tables of Section 2.2 of the PUSAR. With respect to high-energy systems outside containment, the licensee stated in the PUSAR that the only high-energy piping whose dynamic effects loads may be impacted by EPU implementation are the feedwater system and those systems outside containment connected to the feedwater system, due to an increase in feedwater pressure. The effects of the increased pressure were evaluated to determine the effects on the currently postulated dynamic effects loadings resulting from postulated HELBs in the feedwater system piping inside containment, outside containment, and those systems connected to the feedwater system outside containment. As a result of its evaluation, the licensee concluded that the dynamic effects loadings at EPU conditions, resulting from existing postulated HELBs in the aforementioned affected piping, are bounded by the current analysis of record (AOR).

Coupled with the evaluations of the effects of EPU on the dynamic effects associated with currently postulated HELBs at GGNS, the licensee also performed additional dynamic effects evaluations in support of the reconciliation of the GGNS annulus pressurization (AP) loads in response to the issues raised in General Electric – Hitachi Americas LLC (GEH) Safety Communication (SC) 09-01, "Annulus Pressurization Loads Evaluation," dated June 8, 2009. As indicated in PUSAR Section 2.6.2, GEH SC 09-01 was composed to address the potentially non-conservative methodology used in the original design basis calculations of the mass and energy releases from large piping segment breaks within the annulus regions for BWRs. The licensee performed best-estimate mass and energy release calculations for a number of conditions, including OLTP, CLTP, and EPU; the NRC staff's review of these revised mass and energy release calculations is provided in SE Section 2.6. The licensee confirmed that the revised pressure response spectra resulting from the recalculation of the aforementioned AP loads was utilized in evaluating the structural integrity of the RCPB piping and supports, BOP piping and supports, the RPV components and supports, and RPV internals at EPU conditions. The NRC staff's assessment of the effects of EPU implementation on these SSCs is documented below in SE Sections 2.2.2.1, 2.2.2.2, 2.2.2.3, and 2.2.3, respectively.

As indicated in PUSAR Section 2.6.2 and PUSAR Table 2.6-4, the licensee recalculated the jet impingement and jet reaction loads on the RPV and biological shield wall (BSW). Using the revised mass and energy release time histories, these loads were recalculated using the methodologies cited in GGNS FSAR Section 3.6A.2.2 and the criteria of SRP Section 3.6.2. The licensee stated that the reconciliation of these loads also included corrections of inconsistencies and errors identified in the original design basis load calculations. Pipe-whip restraint (PWR) loads were also recalculated based on the reconciled jet impingement and jet reaction loads, described above. As stated in PUSAR Section 2.2.1.2.3, the licensee confirmed that the dynamic effects loadings associated with the CLB requirements at GGNS, related to the protection of SSCs important to safety from dynamic effects loadings, bound the loads which were evaluated at EPU conditions. Furthermore, in response to an NRC staff RAI dated October 6, 2011 (Reference 99), the licensee confirmed in its letter dated October 10, 2011 (Reference 32), that the dynamic effects loads calculated for the RPV and BSW, using the revised AP loads at EPU conditions, remain bounded by the loads used in the evaluations performed at OLTP.

2.2.1.3 Moderate Energy Line Breaks

Section 10.2 of the CLTR indicates that moderate energy piping systems, and portions of systems designated as moderate energy, are typically evaluated at EPU conditions for their effects on equipment qualification. Additionally, the CLTR notes that there are limited effects on the inventories and process parameters associated with moderate energy systems as a result of EPU implementation. Moderate energy piping systems and portions of moderate energy systems, at GGNS are defined in accordance with the criteria found in Section 3.6A.2.1(b) of the GGNS UFSAR. The criteria used to postulate through-wall leakage cracks in moderate energy piping at GGNS is described in GGNS UFSAR Section 3.6A.2.4(d).

While MELB postulation is not explicitly addressed in the CLTR, the licensee indicated in Section 2.5.1.3.2 of the PUSAR that EPU implementation generally does not introduce new MELB locations. This statement was based, in part, on the fact that the process parameters in moderate energy piping systems are not affected by EPU implementation, with two exceptions for GGNS. With respect to MELB consequences, the modification to the circulating water system (CWS) supporting EPU implementation, which increases the flow through the CWS, only affects the spray effects from the presently postulated break. Additionally, the modifications to the Fuel Pool Cooling and Cleanup System (FPCCS), involving the replacement of the FPCCS heat exchangers, will not increase the pressure in this system or any systems supporting the operation of the FPCCS. The licensees also stated in the PUSAR that any temperature changes in moderate energy systems associated with EPU implementation are insignificant.

NRC Staff Evaluation

The NRC staff concludes that the licensee's assessment of the effects of EPU implementation on HELBs, including dynamic effects loadings from HELBs and MELBs, is acceptable, based on the following rationale. The NRC staff concludes that the licensee's use of the criteria of MEB 3-1 to evaluate the effects of EPU implementation on postulated pipe rupture and crack locations is acceptable based on the fact that it is consistent with the CLB requirements related to HELBs, MELBs, and the dynamic effects loadings on affected SSCs at GGNS. Subsequently, the NRC staff concludes that the licensee's conclusion, that no new HELB locations were required to be postulated, is acceptable, based on the licensee's quantitative demonstration that the stresses induced in the high-energy piping due to EPU implementation do not exceed the criteria stipulated in MEB 3-1 for requiring the postulation of an HELB. The NRC staff's determination that the licensee adequately addressed the effects of EPU implementation on the high-energy piping system stresses is based partially on the licensee's RAI responses regarding the main steam and feedwater piping stresses (see SE Section 2.2.2). In these RAI responses, the licensee demonstrated that it had considered the most limiting conditions and all applicable loads in the piping stress analyses performed for the main steam and feedwater systems to support EPU implementation. Additionally, the NRC staff notes that the stress analyses performed by the licensee provided results which are consistent with the guidance provided in the CLTR regarding the effects of EPU implementation on piping systems, in that the licensee demonstrated that the piping stresses are increased in only a limited number of high-energy systems due to EPU implementation. The NRC staff's complete assessment of the licensee's structural evaluations of pressure retaining components (including high-energy piping) is discussed in SE Section 2.2.2.

As indicated in SE Section 2.2.1.2, the licensee evaluated the effects of EPU implementation on dynamic effects loadings, including jet impingement and pipe whip loads, at locations where HELBs are currently postulated. The NRC staff concludes that this scope of evaluation is acceptable given that there are no new HELBs required to be postulated as a result of EPU implementation. The NRC staff also concludes that the licensee's statement that only the feedwater system, and those systems connected to the feedwater system outside containment, required evaluation for dynamic effects loading increases is acceptable based on the fact that the licensee demonstrated that the parameters governing these loads are increased only in these portions of the feedwater system. Subsequently, for the HELBs postulated in these systems, the licensee stated that the dynamic effects loadings in the current AOR bound those which would be induced by EPU conditions. As such, the NRC staff concludes that the licensee's assessment is acceptable, given that the licensee has previously evaluated SSCs, which HELB dynamic effects loads could affect, for loads higher than those which would be realized at EPU conditions. Additionally, the NRC staff concludes that the licensee's assessment is reasonable, given that the pressure increase in the feedwater system is relatively insignificant. Therefore, the dynamic effects loadings would not be expected to increase appreciably.

The NRC staff also concludes that the licensee's assessment of the reconciled jet impingement, jet reaction, and PWR loads on the BSW and RPV, in response to GEH SC 09-01, is acceptable based on the fact that the licensee calculated the revised loads in accordance with methods which are consistent with the GGNS UFSAR and SRP Section 3.6.2. Additionally, the licensee confirmed that the reconciled dynamic effects loads were determined to be less than the dynamic effects loads against which the BSW and RPV have been evaluated previously. Therefore, given that the BSW and RPV have been qualified previously against loads higher than those determined using the revised and corrected AP loads associated with GEH SC 09-01, the NRC staff concludes that there is reasonable assurance that the structural integrity of the BSW and RPV will be maintained in the event that either is subjected to dynamic effects loadings resulting from a rupture of the piping segments within the annulus at EPU conditions. The NRC staff's review of the reconciled mass and energy release calculations associated with the licensee's efforts to address GEH SC 09-01 are included in SE Section 2.6.

As indicated in the summary of the licensee's evaluation of the GGNS MELB analyses in SE Section 2.2.1.3 above, the effects on moderate energy systems at GGNS resulting from EPU implementation do not result in any pressure increases in the affected systems and only result in insignificant temperature increases in affected systems. Additionally, based on the fact that the flow increase in the CWS only affects the spray rate resulting from the existing postulated MELB in the GGNS, it can be concluded that all of the process parameter changes in the affected moderate energy systems do not result in any significant increases in the stresses within the affected piping systems. Based on this conclusion and the criteria stipulated in MEB 3-1 for postulating MELB locations, the effects on the moderate energy systems at GGNS resulting from EPU implementation would not result in new postulated MELB locations. Therefore, the NRC staff concludes that the licensee's statement that EPU implementation does not generally require the postulation of new MELB locations is acceptable and applicable to EPU implementation at GGNS.

Conclusion

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

2.2.2 Pressure-Retaining Components and Component Supports

Regulatory Evaluation

The NRC staff has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the ASME Code, Section III, Division 1, and GDC 1, "Quality standards and records," GDC 2, "Design bases for protection against natural phenomena," GDC 4, "Environmental and dynamic effects design bases," GDC 14, "Reactor coolant pressure boundary," and GDC 15, "Reactor coolant system design." 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 cumulative fatigue usage factors (CUFs) against the Code-allowable limits.

The NRC's acceptance criteria are based on (1) 10 CFR 50.55a, "Codes and standards," and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (4) GDC 14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (5) GDC 15, insofar as it requires that the RCS be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation.

Specific review criteria are contained in SRP Sections 3.9.1, "Special Topics for Mechanical Components," 3.9.2, "Dynamic Testing and Analysis of Systems, Structures, and Components," 3.9.3, "ASME Code Class 1, 2, and 3 Components, and Component Supports, and Core Support Structures," and 5.2.1.1, "Compliance with the Codes and Standards Rule, 10 CFR 50.55a" (Reference 62), in addition to other guidance provided in Matrix 2 RS-001 (Reference 54). The NRC staff's review also considered the guidance provided in Sections 3.2 and 3.5 of the CLTR (Reference 55), which contain NRC staff-approved methodologies for evaluating the effects of EPU implementation on the structural and pressure boundary integrity of the reactor pressure vessel (RPV) and its supports and safety-related piping systems, respectively. Section 3.4.1 of the CLTR discusses the effects of flow-induced vibration (FIV) on affected safety-related piping systems and provides an NRC-approved methodology for evaluating the effects of FIV on the structural integrity of these piping systems. The NRC staff's review and approval of these methodologies, including any limitations on their use, is documented in an SER enclosed with the CLTR (Reference 55).

Technical Evaluation

The licensee evaluated the effects of EPU implementation on pressure-retaining components and component supports at GGNS to ensure that structural and pressure boundary integrity of these components and their supports would be maintained following EPU implementation. This evaluation included assessments of the RCPB piping, components, and supports, BOP piping, components, and supports, the RPV and supports and the effects of FIV on the structural integrity of the aforementioned pressure-retaining components. The evaluation presented below is structured to provide a summary of the licensee's evaluations, performed in support of EPU implementation for each of the aforementioned SSCs, followed by the NRC staff's assessment of the licensee's evaluations. The NRC staff's assessment is based on the acceptance criteria outlined in the regulatory evaluation, above, and is focused on ensuring that the licensee has provided reasonable assurance that the structural and pressure boundary integrity of the aforementioned SSCs will remain adequate following EPU implementation at GGNS.

2.2.2.1 Reactor Coolant Pressure Boundary Piping, Components, and Supports

In Section 2.2.2.2.1 of the PUSAR (Reference 57), the licensee provided the results of its structural evaluations of the RCPB piping, components, and supports under EPU conditions. In accordance with the methodology outlined in the CLTR, the licensee stated that systems not experiencing an increase in flow, pressure, temperature, and mechanical loads as a result of EPU implementation will, correspondingly, not experience increases in stresses and fatigue. Accordingly, the licensee denotes systems which are unaffected by EPU in the proprietary portions of Section 2.2.2.2.1.1 of the PUSAR. Additional justification for classifying these systems as unaffected by EPU implementation is located in the proprietary portions of Table 2.2-2 of the PUSAR. The licensee's evaluation of the effects of EPU implementation on the vibrations of the RCPB piping and components is discussed in SE Section 2.2.2.4.

Utilizing the guidance outlined in the CLTR to determine which RCPB piping systems required further structural evaluations to support EPU implementation (i.e., the affected piping systems), the licensee determined that the main steam and feedwater piping systems (inside containment), including branch piping connected to these systems up to the first anchor or support, will experience increases in the aforementioned governing parameters (flow, temperature, and pressure). As Table 1-2 of the PUSAR indicates, the RPV dome pressure will not be increased as part of EPU implementation. However, the total steam flow at GGNS will be increased from 16.774 million pounds per hour (Mlb/hr) to 18.968 Mlb/hr while the feedwater flow will increase from 16.741 Mlb/hr to 18.935 Mlb/hr as part of EPU implementation at GGNS. The licensee stated in the PUSAR that EPU implementation has no effect on the main steam piping pressures or temperatures. Additionally, the licensee stated that there is a negligible effect on the feedwater pressure and temperature as a result of EPU implementation. In response to an NRC staff RAI dated May 20, 2011 (Reference 95), regarding the conditions at which the feedwater piping system was evaluated in support of EPU implementation, the licensee confirmed in its RAI response dated June 15, 2011 (Reference 19), that the feedwater piping stress evaluations were carried out at the most limiting conditions expected at the proposed EPU power level.

The licensee evaluated the affected RCPB piping in accordance with the guidance stipulated in Appendix K of ELTR1. As shown on Figure K-1 of Appendix K to ELTR1, the heat balance of the reactor coolant system is used to formulate scaling factors based on increases in flow, temperature, and pressure resulting from EPU implementation. The scaling factors developed based on the parameter increases are used to determine increases in piping system stresses, fatigue usage, displacements and piping interface loads as a result of EPU implementation. These values establish the structural behavior of the piping systems at EPU conditions and they are then compared to the acceptance criteria established by the design Code of record against which the system and its associated components and supports were designed. By satisfying these established acceptance criteria, the piping system is determined to be structurally adequate for EPU implementation.

The main steam system piping, including the branch piping, inside containment was designed in accordance with the provisions of Subsection NB of the 1980 Edition of the ASME Code, Section III. By letter dated February 23, 2011 (Reference 6), in response to an NRC staff RAI dated January 27, 2011 (Reference 94), regarding the feedwater system piping, the licensee stated that the feedwater piping inside containment was originally designed in accordance with the provisions of the 1974 Edition through the 1975 Summer Addenda of the ASME Code, Section III. In response to a separate RAI by letter dated February 23, 2011, the licensee provided the design codes of record for the piping supports at GGNS. As indicated in the licensee's RAI response, hangers and supports were designed in accordance with the 1974 Edition of the ASME Code, Section III, while snubbers at GGNS were designed in accordance with the 1974 Edition of Section III of the ASME Code, including the Addenda of Summer 1974.

Based on the scaling factors developed in accordance with the ELTR1, Appendix K methodology described above, the licensee provided the percentage increases in the applicable ASME Code equations, interface loads and thermal displacements for the Class 1, 2, and 3 main steam and feedwater piping in Tables 2.2-3a and 2.2-3b of the PUSAR. As shown in the PUSAR tables, and discussed above, the absence of temperature and pressure increases in the main steam and feedwater system piping at EPU conditions resulted in stress and interface load increases due solely to the increase in system flow rates at EPU conditions. The largest increase in pipe stresses and interface loads resulted from the turbine stop valve closure (TSVC) transient, which is governed by the main steam flow rate and bounds transient loads resulting from the main steam isolation valve (MSIV) closure event. The licensee stated that the increase in stresses and interface loads were determined by increasing the TSVC transient loads to EPU conditions using the aforementioned scaling factors. Additionally, the licensee noted that other loads used in the analysis of record (AOR) for the main steam and feedwater piping system, including those due to seismic events, SRV discharge, AP, chugging, and condensation oscillation (CO), are not affected by EPU implementation.

Using the scaling factors from Table 2.2-3a of the PUSAR, the licensee calculated the stresses and fatigue usage factors on the limiting locations of the four MSLs, main steam penetrations, MSL nozzles, flanges, and supports and compared the calculated results to the applicable ASME Code acceptance criteria for these main steam SSCs. Based on the results of the licensee's structural evaluation of the main steam system piping, penetrations, nozzles, flanges, and supports, which are presented in Tables 2.2-4a through 2.2-4l of the PUSAR, the licensee concluded that the main steam system is structurally adequate for operation at the proposed EPU power level. This was demonstrated in the aforementioned tables, which show that at

EPU conditions, the ASME Code design criteria continues to be satisfied for the aforementioned main steam SSCs.

The branch piping attached to the main steam piping includes the SRV discharge line, portions of the RCIC system, the RPV vent and main steam drain lines, including the MSIV drain. The licensee evaluated the effects of EPU on the structural and pressure boundary integrity of the branch piping attached to the main steam headers and determined that EPU has no effect on the structural qualification of these branch lines. This conclusion was based on the licensee's assertion that the flow increase in the MSLs does not adversely affect the branch piping which, subsequently, does not result in any stress increases in the piping and imparts no additional loading on the branch piping supports. There is also no variation in the pressure and temperature of the main steam piping and attached piping between CLTP and EPU conditions. Additionally, as indicated above, the external loads used in the current AOR, such as seismic, SRV discharge, AP, CO, and chugging, are not affected by EPU implementation and, therefore, do not affect the structural qualification of the branch piping. Based on the fact that the main steam branch piping is unaffected by EPU implementation, the licensee concluded that the piping remains structurally adequate for EPU implementation.

With respect to the evaluation of the feedwater system piping inside containment, including branch piping connected to the feedwater system, the licensee evaluated the effects of the flow, temperature, and pressure changes which would result in the system as a result of EPU implementation. Based on these changes, the licensee evaluated the effects on the stress and fatigue analyses of the feedwater piping, RPV feedwater nozzles, penetrations, flanges, valves, and supports inside containment using the aforementioned scaling factors; SE Section 2.2.2.3 includes an evaluation of the feedwater nozzles as part of the evaluation of the RPV structure and components. The licensee concluded that the feedwater piping stress analyses were not affected by the changes in the temperature and pressure in the system at the proposed power level, based on the insignificant changes in these parameters at EPU conditions. Additionally, while the feedwater flow increases by 13.1 percent from the CLTP flow rate, the licensee stated that this also did not affect the feedwater piping stress analyses due to the fact that water-hammer loads were not included in the design-basis analyses of the feedwater piping system.

By letter dated June 15, 2011 (Reference 19), in response to an NRC staff RAI dated May 20, 2011 (Reference 95), the licensee confirmed that water-hammer events were not included as part of the design-basis evaluations performed for the feedwater piping system. Additionally, the licensee indicated that other occasional and transient loadings used in the design-basis stress analyses of the feedwater system (inside and outside of containment) were not affected by the increased flow rate. As such, the licensee concluded that the increase in flow would have no adverse effect on the structural and pressure boundary integrity of the feedwater piping system. However, by letter dated August 25, 2011 (Reference 24), in response to an additional NRC staff RAI dated August 3, 2011 (Reference 96), the licensee stated that it had quantified the effects of the most limiting operating transient which could be affected by flow rate.

The licensee indicated that this limiting transient is the trip of both reactor feedwater pumps and it provided a quantitative summary of the loadings which this transient would induce on the feedwater piping system at EPU conditions, in addition to a graphical representation of the loading time history. The licensee's hydraulic analyses of the limiting transient yielded a pressure wave acting on the feedwater piping system which results in a load of 0.017 g at EPU conditions. The licensee stated that the feedwater piping AOR currently include a load of 2 g, attributed to SRV actuations, for loading combinations where transient loads are included. The licensee stated that the inclusion of loads due to the reactor feedwater pump trip would result in a negligible increase in the total piping design load when compared to the loads induced on the piping from SRV actuation, in combination with other loads due to deadweight, thermal, seismic and AP anchor motion, and SSE. The relatively low magnitude of the pressure wave load was attributed to the inertial effects afforded by the design of the GGNS reactor feedwater pumps, which allows the pump to coast down rather than stop in a short period of time. With respect to water-hammer events, the licensee stated that all feedwater isolation valves stroke in times which are too slow to result in a water-hammer event (between 32 and 100 seconds). Additionally, the licensee indicated that the feedwater system design precludes the possibility of a water-hammer event resulting from cavity generation and collapse in the system. As such, given that the feedwater flow increase accompanying EPU implementation does not result in any increases in feedwater pipe stresses, the licensee concluded that the results of the structural evaluations performed for the feedwater system piping, components, and supports remain valid as presented in the PUSAR.

NRC Staff Evaluation

The NRC staff has reviewed the licensee's assessment of the RCPB piping systems and concludes that the licensee's assessment of the systems is acceptable. Using the methodology outlined in the CLTR, the licensee was able to disposition a number of RCPB piping systems, or portions of systems, as being unaffected by EPU implementation. The NRC staff concludes that these dispositions are acceptable based, in part, on the fact that the licensee's determinations were made consistent with the guidance of the CLTR, which has been previously approved for use by the NRC staff. Based on the above, the NRC staff focused its review on the main steam and feedwater piping systems, which were the only RCPB piping systems determined by the licensee to be affected by EPU implementation at GGNS.

As indicated in SE Section 2.2.2, the NRC staff's review focused on determining whether the affected piping, components, and supports of the RCPB would continue to satisfy the structural acceptance criteria to which the RCPB SSCs were designed. The NRC staff notes that the licensee confirmed that the main steam and feedwater system piping, components, and supports, including branch piping, were evaluated for acceptability at EPU conditions in accordance with the criteria to which they were originally designed (i.e., the ASME Code editions and addenda identified above). By evaluating the RCPB piping, components, and supports against the criteria to which it was originally designed, the NRC staff notes that this approach ensures that the structural capacities originally intended for the RCPB piping, components, and supports are not exceeded at EPU conditions. This, in turn, provides reasonable assurance that EPU implementation does not result in conditions which are greater than those for which the piping was originally designed.

The licensee's method of determining the stresses and fatigue usage factors in the RCPB piping, components, and supports, based on the increases in flow, pressure and temperature in the RCPB systems at EPU conditions, is consistent with the methods outlined in the CLTR and, correspondingly, Appendix K of ELTR1. The NRC staff concludes that the use of the methodologies in these two LTRs is acceptable for determining the stresses and fatigue usage factors in the RCPB piping, components, and supports is acceptable based on the fact that both

LTRs have been reviewed and approved previously by the NRC staff. Given that the temperature and pressure in the main steam and feedwater systems, and piping attached to these systems, do not change or are negligibly affected at EPU conditions, the NRC staff's review focused on the effects of the EPU-induced flow increases on the structural integrity of the RCPB piping, components, and supports.

The NRC staff reviewed the results of the licensee's assessment of the main steam piping, components, and supports to verify that the applicable ASME Code-allowable values would continue to be satisfied following EPU implementation. The NRC staff notes that the licensee conservatively applied the aforementioned scaling factors in determining the stresses, fatigue usage factors and interface loads which will be imparted on the main steam system following EPU implementation. The use of this methodology included the use of the scaling factors to develop the limiting TSVC loads under EPU conditions. In its review of Tables 2.2-4a through 2.2-4l of the PUSAR, the NRC staff notes that the licensee quantitatively demonstrated that the RCPB portions of the main steam piping, penetrations, supports, nozzles and flanges all meet their applicable design code-allowable values at EPU conditions. Therefore, based on the fact that the licensee demonstrated that these portions of the RCPB will continue to satisfy their structural design-basis requirements following EPU implementation, the NRC staff concludes that there is reasonable assurance that the structural integrity of these portions of the RCPB will be maintained following EPU implementation.

In reviewing the licensee's assessment of the RCPB portions of the feedwater system, the NRC staff focused on the effects of EPU implementation on the structural and pressure boundary integrity of the feedwater system. Similar to the main steam system, the NRC staff noted that the temperature and pressure changes in the feedwater system at EPU conditions are insignificant and are nearly identical to the temperature and pressure under CLTP conditions. Therefore, the NRC staff focused on the effects of the feedwater flow increase in assessing the structural integrity of the feedwater system piping. By letter dated June 15, 2011 (Reference 19), in response to an NRC staff RAI dated May 20, 2011 (Reference 95), the licensee stated that the flow increase had no bearing on the feedwater piping stress analyses due to the fact that the design basis of the feedwater system piping did not include loads due to transients whose behavior was governed by feedwater flow, unlike the main steam system (i.e., TSVC transient loads). However, based on the guidance in the CLTR, which specifically denotes the effects of temperature, pressure, and flow increases on piping system stresses, the NRC staff requested the licensee to provide a technical justification demonstrating that the feedwater flow increase resulting from EPU implementation did not result in the design-basis structural acceptance criteria of the RCPB portions of the feedwater system being exceeded.

The NRC staff reviewed the licensee's RAI response dated August 25, 2011 (Reference 24), regarding the feedwater piping stress analysis and concluded that the response was acceptable. This conclusion was based on the fact that the licensee quantified the effects which the feedwater flow increase, resulting from EPU implementation, would have on the feedwater system piping stress analyses. The NRC staff notes that the licensee evaluated the most limiting transient in quantifying these effects (reactor feedwater pump trip). For the limiting transient, the NRC staff reviewed the loads which would be imparted on the feedwater system piping and compared these loads with loads which are already included in the feedwater pipe stress analyses. The NRC staff concludes that the transient loads are insignificant when compared to other loads used in the current AOR for the feedwater piping (i.e., SRV actuation loads). Therefore, the NRC staff concludes that the exclusion of loads due to transients whose magnitudes are influenced by flow rate is acceptable due to the fact that these loads would have a negligible impact on the overall piping stress analyses and subsequent qualification of the piping.

In reviewing the licensee's RAI response regarding the feedwater system piping, the NRC staff also considered the licensee's description of the feedwater system design as it relates to water hammer-induced loads in the piping system. The NRC staff concludes that the licensee's statement that isolation valve closures do not result in water-hammer events, is acceptable based on the fact that the licensee was able to show that all of the isolation valves within the feedwater system have closing times which are too large to result in a valve closure water-hammer event. The NRC staff notes that fast closure valve transients rely on very abrupt isolation valve closures times in order to generate significant loads on a piping system. Given that flow is the only feedwater system parameter significantly affected by EPU implementation, coupled with the fact that the licensee has adequately demonstrated that flow-induced loads are not significant in the GGNS feedwater piping, the NRC staff concludes that the licensee's overall conclusion, that the feedwater piping, components, and supports do not see an appreciable increase in stresses resulting from EPU implementation, is acceptable. Furthermore, given that the feedwater piping system will not see an appreciable increase in stress at EPU conditions, the NRC staff concludes that the design criteria applicable to the RCPB portion of the feedwater system will continue to be satisfied following EPU implementation at GGNS.

Therefore, based on the above, the NRC staff concludes that there is reasonable assurance that the portions of the RCPB piping systems affected by EPU implementation at GGNS will maintain their structural integrity following EPU implementation. This is based on the licensee's demonstration that 1) most of the RCPB piping systems, or portions of systems, are unaffected by EPU implementation due to the fact that there is no increase in pressure, temperature, flow, or other loads used in the design basis of these unaffected portions of the RCPB and 2) the portions of the main steam and feedwater piping systems affected by the proposed EPU implementation will continue to meet the applicable structural acceptance criteria to which these systems were originally designed. The NRC staff's review of the effects of EPU implementation on the vibration of the RCPB piping and components is included in SE Section 2.2.2.4.2.

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

The licensee evaluated the structural and pressure boundary integrity of the balance-of-plant (BOP) piping systems at EPU conditions in Section 2.2.2.2.2 of the PUSAR (Reference 57). This evaluation included an assessment of both safety related and non-safety-related BOP piping systems. The licensee stated that BOP piping systems not experiencing an increase in pressure, temperature, flow, or other mechanical loads as a result of EPU will not experience any corresponding increase in piping stresses and, thus, these systems are deemed unaffected and remain structurally adequate for EPU implementation. The following BOP piping systems were classified by the licensee as unaffected by EPU implementation: auxiliary steam piping, circulating water piping, component cooling water (CCW) piping, condensate and refueling water storage transfer piping, condensate cleanup piping, condenser air removal piping, control rod drive (CRD) piping (excluding the CRD insert, withdraw and sensing lines inside containment), moisture separator reheater (MSR) relief valve discharge piping, drywell chilled water piping, fuel pool cooling (FPC) and cleanup piping, hydrogen water chemistry (HWC) piping, liquid radwaste piping, main steam drain and MSIV drain piping (outside containment), offgas piping, plant chilled water piping, plant service water (PSW) piping, post-accident sampling piping, process sampling piping, reactor water cleanup (RWCU) piping beyond the first anchor, standby liquid control (SLC) piping (outside containment), standby service water (SSW) piping, turbine building cooling water (TBCW) piping, and the SRV discharge line (SRVDL) piping beyond the first anchor to the quenchers.

Conversely, the following BOP piping systems, or portions of systems, were determined by the licensee to be affected by EPU implementation: the high pressure core spray (HPCS) piping beyond the first anchor, low pressure core spray (LPCS) piping beyond the first anchor, RCIC piping beyond the first anchor, RHR piping beyond the first anchor, containment spray piping, main steam and reheat piping (outside containment), feedwater piping (outside containment), extraction steam piping, condensate piping, moisture separator reheater vents and drains piping, feedwater heater vents and drains piping, and the sealing steam piping.

The effects of EPU implementation on these systems are quantified in Table 2.2-6 of the PUSAR, with a brief description of the effects of EPU implementation on the AOR for these piping systems. Similar to the evaluation performed for the affected portions of the RCPB piping systems, the licensee stated that changes in temperature, pressure, and flow rate were evaluated to determine the specific effects of EPU implementation on the structural and pressure boundary integrity of these piping systems. Consideration was also given to the effects of EPU implementation on other loads used in the AOR for these piping systems (i.e., seismic, chugging, AP, CO, and design-basis accident (DBA) loss-of-coolant accident (LOCA) loads). Based on the changes in these parameters, the licensee stated that the stress analyses (as applicable) for the various systems were reconciled to determine whether the design-basis acceptance criteria, used in the original design of each system, would continue to be satisfied following EPU implementation. The results of these stress reconciliations are presented in PUSAR Tables 2.2-5a through 2.2-5h. The licensee stated that systems not requiring a detailed analysis to support EPU implementation were evaluated to determine whether pipe routing and flexibility would remain acceptable following EPU implementation.

The PUSAR states that the main steam and feedwater system piping, including branch piping, outside containment was evaluated for acceptability at EPU conditions in accordance with the provisions of the 1974 Edition, with Addenda through summer 1975, of the ASME Code, Section III, with exceptions. The licensee also stated that some subsections from the 1977 Edition, with Addenda through summer 1979, and the 1980 Edition, with Addenda through summer 1981, of the ASME Code were used in the evaluation of these systems. These code provisions were also used in the evaluation of other Class 2 and 3 BOP piping, as indicated on page 2-57 of the PUSAR. In response to an NRC staff RAI dated January 27, 2011 (Reference 94), regarding the Codes of record used to evaluate the BOP portions of the main steam and feedwater system, the licensee confirmed in its letter dated February 23, 2011 (Reference 6), that the exceptions used in the evaluation are consistent with the CLB requirements related to these portions of the main steam and feedwater systems. The design Code of record used by the licensee to evaluate safety-related pipe supports is provided in SE Section 2.2.2.2.1.

In its evaluation of the BOP portions of the main steam piping system, the licensee stated that the evaluation performed to support EPU implementation considered the effects of the main steam flow rate, pressure, and temperature at the proposed EPU power level on the structural and pressure boundary integrity of the main steam system piping, supports, nozzles, flanges, valves, and the associated building structure. The results of the evaluation of the BOP portions of the main steam system piping are located in Tables 2.2-5a and 2.2-5b of the PUSAR. Table 2.2-5a addresses the limiting portions of the Class 1 main steam piping outside containment (i.e., containment penetration), which is only affected by the increased TSVC transient loads resulting from EPU implementation. This portion of the main steam piping system was evaluated consistent with the methods in Appendix K of the ELTR1 and the main steam containment penetration was shown to satisfy the applicable acceptance criteria at EPU conditions.

For the Class 2 and non-safety-related portions of the main steam system outside containment, the licensee's evaluation is documented in Table 2.2-5b of the PUSAR. In contrast to the evaluation performed for the RCPB portion of the main steam piping, which used scaling factors to reconcile the stresses resulting from the higher TSVC transient loads, the licensee stated in the PUSAR that detailed steam-hammer-forcing functions were developed to characterize the TSVC loads which would be imparted on the Class 2 and non-safety-related portions of the main steam piping at EPU conditions. By developing more realistic steam-hammer-forcing functions, in lieu of using the scaling factors to determine the main steam piping and support stresses, the licensee stated that the applicable ASME Code requirements were shown to be satisfied at EPU conditions in Table 2.2-5b of the PUSAR.

In response to an NRC staff RAI dated January 27, 2011 (Reference 94), regarding the use of realistic steam-hammer-forcing functions to model the TSVC transient loads, by letter dated February 23, 2011 (Reference 6), the licensee stated that the revised loads were developed using the STEHAM computer program and that the use of this methodology was only employed to evaluate the main steam piping outside of containment. In its response to a subsequent NRC staff RAI dated May 20, 2011 (Reference 95), regarding the use of the STEHAM computer program in similar applications, the licensee stated in its letter dated June 15, 2011 (Reference 19), that the original TSVC transient loads for the main steam piping outside containment had been developed using hand calculations. Additionally, the licensee stated that STEHAM had been employed in the development of steam-hammer-forcing functions for nuclear power plant designs since 1975. The licensee also cited precedent licensing actions which have been supported, in part, by the use of STEHAM, noting that it has been previously approved for use by the NRC staff in power uprates.

The licensee's evaluation of the BOP portions of the feedwater piping, components, and supports is described in Section 2.2.2.2.2.2 of the PUSAR and quantified in Tables 2.2-5c and 2.2-5d of the PUSAR. As stated in the PUSAR, a slight increase in operating temperature and pressure is experienced by the BOP piping portions of the feedwater piping at EPU conditions; these slight increases are reflected in the aforementioned tables and show a negligible effect on feedwater piping stresses due to pressure and a maximum 1.6 percent increase in stress due to the temperature increase. Regarding other external loads used in the analyses of the feedwater piping system, the licensee stated that loads such as seismic, chugging, and CO were not affected by EPU. Additionally, the licensee stated that AP loads do not affect piping outside containment.

Based on these considerations, the licensee's assessment of the BOP portions of the feedwater piping system at EPU conditions concluded that the AOR for the feedwater piping contain adequate margin to accommodate the slight pressure and temperature increases. Additionally, the licensee stated that the CLB related to the feedwater system interfaces, including penetrations, flanges and valves, remain valid at EPU conditions. An evaluation of the effects of the aforementioned operating temperature increase was carried out to determine whether thermal expansion of the affected portions of the feedwater piping system would result in unacceptable performance of the feedwater pipe supports or nozzles which attach equipment to the feedwater system piping. The licensee determined that thermal expansion resulting from this temperature increase did not result in any of the supports exceeding the criteria specified by their applicable design codes of record. Additionally, the loads imparted on the aforementioned nozzles were determined to be acceptable.

With respect to the effects of the feedwater flow increase on the stresses in the BOP portions of the feedwater piping system, the licensee stated that the feedwater flow increase resulting from EPU implementation did not affect the system stresses due to the fact that water-hammer transient loads were not included as a load in the original system design, similar to the RCPB portion of the feedwater system. However, as discussed in Section 2.2.2 the licensee provided additional information on the feedwater system piping stresses (RCPB and BOP portions) in response to an NRC staff RAI regarding the effects of the flow increase on the structural integrity of the feedwater piping system. Based on the information contained in the RAI response, the licensee was able to confirm that EPU does not result in an increase in stresses and fatigue (as applicable) in the BOP portions of the feedwater piping system.

A summary of the licensee's assessment of BOP piping systems other than the main steam and feedwater systems is also included within Section 2.2.2.2.2.2 of the PUSAR. Similar to the evaluation of the RCPB piping and the other BOP piping previously discussed, the licensee's assessment focused on whether the flow, pressure, temperature, or other loads in these piping systems are affected by EPU implementation. As previously stated, if these parameters remain unaffected by EPU implementation, the stresses and fatigue (if applicable) in these piping systems are also unaffected by EPU implementation. As quantified in Table 2.2-6 of the PUSAR, there are no appreciable changes in pressure in any of the BOP piping systems evaluated to support EPU implementation. Additionally, flow rates for all BOP piping, excluding the main steam and feedwater piping, are not affected by EPU implementation. Therefore, the licensee's assessments of BOP piping other than the main steam and feedwater piping focused on whether these piping systems could accommodate the effects of higher temperatures and changes in other external loads imparted on the piping, components, and supports which make up these systems.

The results of the licensee's evaluations are discussed in the aforementioned PUSAR section and percentage increases in the loadings imparted on affected piping systems are provided in Tables 2.2-5e through 2.2-5h of the PUSAR. These tables show that pipe stresses and pipe support loads are only affected by temperature increases, with the greatest increase being imparted on the ECCS piping and pipe supports. This increase, as indicated in the footnote to Table 2.2-6 of the PUSAR, results from a conservative assessment of the increase in suppression pool temperature which results from higher core decay heat at EPU conditions. The licensee stated that the evaluation performed for these portions of affected ECCS piping systems concluded that the existing piping and pipe support analyses remain valid and are able to accommodate the increases in suppression pool temperature. Additionally, with respect to its assessment of other affected piping systems, the licensee concluded that all piping, supports, and attached equipment nozzles have adequate design margin to accommodate the effects of increased loads and displacements (i.e., thermal expansion movement) resulting from the proposed EPU at GGNS.

NRC Staff Evaluation

The NRC staff has reviewed the licensee's assessment of the BOP piping systems and concluded that the licensee's assessment of the structural and pressure boundary integrity of the BOP piping systems is acceptable. The NRC staff's review of the licensee's assessment of the BOP piping systems was performed similar to its review of the assessment of the RCPB piping. Using the methodology outlined in the CLTR, the licensee was able to disposition a number of BOP piping systems, or portions of systems, as unaffected by EPU implementation. The NRC staff concludes that these dispositions are acceptable based on the fact that the licensee's determinations were made consistent with the guidance of the CLTR, which has been previously approved for use by the NRC staff. Based on the above, the NRC staff focused its review on those BOP piping systems, or portions of systems, which the licensee was unable to disposition as unaffected by the proposed EPU.

As indicated in SE Section 2.2.2, the NRC staff's review focused on determining whether the piping, components, and supports of the BOP piping systems affected by EPU implementation will continue to satisfy the acceptance criteria to which the BOP SSCs were designed, including any applicable codes of record used in the design of these SSCs. The licensee confirmed that the BOP piping SSCs were evaluated for acceptability at EPU conditions in accordance with the original design criteria applicable to each SSC. This confirmation extends to the exceptions taken to portions of the ASME Code, which were described in the licensee's RAI responses regarding the codes of record applicable to the BOP piping. The NRC staff concludes that the licensee's use of the exceptions cited within the PUSAR is acceptable based on the fact that the exceptions taken are consistent with the CLB requirements related to the design of the BOP piping systems.

The NRC staff's review of the licensee's assessment of the BOP portions of the main steam piping focused on the methodology used in the evaluation and the results of the evaluation. The NRC staff notes that a majority of the licensee's reconciliation of the stresses and fatigue usage factors (as applicable) of the main steam piping system at EPU conditions was performed consistent with the methods outlined in the CLTR and, correspondingly, Appendix K of ELTR1. This methodology is described above in the NRC staff's evaluation of the RCPB piping SSCs and the NRC staff concludes that the use of this methodology is acceptable and consistent with the guidance previously approved by the NRC for use in EPU evaluations for BWRs. However, the NRC staff also notes that the licensee opted to utilize an alternative methodology to scale the stresses due to the TSVC loads in the Class 2 and non-safety-related portions of the main steam piping outside containment.

While the licensee did not employ the generic scaling factors in its evaluation of the loads caused by the TSVC transient in the Class 2 and non-safety-related portions of the main steam system piping outside containment, the NRC staff concludes that the licensee's use of the STEHAM computer program to develop detailed steam-hammer-forcing functions and plant-specific scaling factors is acceptable based on the following: 1) the stipulation in Section 3.4 of the NRC staff SER regarding the CLTR, which states that detailed analyses supporting a pipe stress analysis may be performed if design code-allowable values cannot be satisfied using the scaling factor method to reconcile stresses in affected piping systems and 2) STEHAM has been employed in similar applications to develop steam-hammer time histories since 1975, including recent EPU LARs (i.e., the EPU for Point Beach Nuclear Plant, Units 1 and 2).

The NRC staff reviewed the results of the licensee's assessment of the stresses and fatigue usage factors developed at EPU conditions in the BOP portions of the main steam piping, components, and supports to verify that the applicable design code-allowable values would continue to be satisfied following EPU implementation. In its review of Tables 2.2-5a and 2.2-5b of the PUSAR, the NRC staff notes that the licensee quantitatively demonstrated that the limiting locations of the BOP portions of the main steam piping, all meet their applicable design code-allowable values at EPU conditions. Additionally, the NRC staff notes that the licensee confirmed that all of the main steam system supports and turbine nozzles will continue to maintain adequate margin against increased loads and displacements resulting from EPU implementation. Therefore, based on the fact that the licensee has demonstrated that these portions of the main steam system will continue to satisfy their applicable structural design-basis requirements following EPU implementation, the NRC staff concludes that there is reasonable assurance that the structural integrity of these portions of the main steam system will be maintained following EPU implementation.

In reviewing the licensee's assessment of the BOP portions of the feedwater system, the NRC staff focused on the effects of the feedwater flow increase in assessing the structural integrity of the feedwater system piping, given that EPU has an insignificant effect on the temperature, pressure and other loads used in the AOR for the BOP portions of the piping system. As indicated in the discussion of the RCPB portions of the feedwater piping, the licensee stated in its June 15, 2011, response to an NRC staff RAI that the flow increase had no bearing on the feedwater piping stress analyses due to the fact that the design basis of the feedwater system piping did not include loads due to transients whose behavior was governed by feedwater flow, unlike the main steam system (i.e., TSVC transient loads). However, based on the guidance in the CLTR, which specifically denotes the effects of temperature, pressure, and flow increases on piping system stresses, the NRC staff requested the licensee to provide a technical justification demonstrating that the feedwater flow increase resulting from EPU implementation did not result in the design-basis structural acceptance criteria of the RCPB portions of the feedwater system being exceeded.

As discussed in SE Section 2.2.2.2, the NRC staff reviewed the licensee's August 25, 2011, RAI response which provided the NRC staff with reasonable assurance that the licensee has adequately addressed the impact of the flow increase on the structural and pressure boundary integrity of the feedwater piping. The NRC staff's conclusion in SE Section 2.2.2.2, regarding this reasonable assurance, extends to the BOP portions of the feedwater piping given that the loads used in the stress analyses of the feedwater system piping, which are governed by flow rate, are common to both the RCPB and BOP portions of this system at GGNS.

With respect to its review of the licensee's assessment of BOP piping systems other than the main steam and feedwater systems, which are affected by EPU implementation, the NRC staff focused on the effect of EPU implementation on the AOR for these affected systems.

Consistent with the guidance of the CLTR and ELTR1, the licensee determined the applicable increases in stresses and displacements of the SSCs associated with the affected systems due to the temperature increases associated with EPU implementation (flow, pressure, and other loads used in the analyses are unaffected by EPU for these systems). The NRC concludes that the licensee's method of scaling is acceptable based on the fact that the licensee utilized the NRC-approved methodology in the aforementioned LTRs. The NRC staff notes that the licensee confirmed that the loads imparted on the affected BOP piping systems, resulting from the temperature increases at EPU implementation, did not result in any of the piping, components, or supports exceeding their available design margins. The NRC staff also gave consideration to the fact that the licensee used a conservatively high value in evaluating the effects of the increased suppression pool temperature on the structural and pressure boundary integrity of the ECCS piping, components, and supports affected by this increased temperature. Therefore, based on licensee's demonstration that there exists adequate design margin in the BOP piping systems affected by EPU implementation to accommodate the effects of the aforementioned temperature increases in these systems, the NRC staff concludes that there is reasonable assurance that the structural and pressure boundary integrity of these portions of BOP piping systems will be maintained following EPU implementation.

Based on the above, the NRC staff concludes that there is reasonable assurance that the portions of the BOP piping systems affected by EPU implementation at GGNS will maintain their structural and pressure boundary integrity following EPU implementation. This is based, in part, on the licensee's demonstration that 1) certain BOP piping systems, or portions of systems, are unaffected by EPU implementation due to the fact that there is no increase in pressure, temperature, flow, or other loads used in the design bases of these unaffected portions of BOP piping systems and 2) the portions of BOP piping systems affected by the proposed EPU implementation will continue to meet the applicable structural acceptance criteria to which these systems were originally designed. The NRC staff's review of the effects of EPU implementation on the vibration of the BOP piping and components is included in SE Section 2.2.2.4.

2.2.2.3 Reactor Vessel and Supports

In Section 2.2.2.3 of the PUSAR (Reference 57), the licensee evaluated the RPV structure and its support components, which constitute a portion of the RCPB, to determine whether the structural adequacy of these structures and components would be maintained following EPU implementation at GGNS. The licensee's evaluation focused on ensuring that EPU implementation at GGNS does not result in increases in stresses and fatigue usage which exceed the structural acceptance criteria for which the RPV structure and supporting components were designed. The structural design-basis information related to these components, including applicable loads and loading combinations used in their design, is located in GGNS UFSAR Section 3.9. Table 3.9-2 of GGNS UFSAR Section 3.9 includes these loads and loading combinations in addition to the specific acceptance criteria (i.e., stress limits) used to structurally qualify the RPV structure and support components at OLTP conditions. These criteria were used subsequently by the licensee to evaluate the RPV and its supports at EPU conditions.

The licensee stated in the PUSAR that the RPV structure and supporting components were designed in accordance with the provisions of the 1971 Edition, up to and including the winter 1972 Addenda, of Section III of the ASME Code. For components which were modified following their original design, the licensee provided the Code of record used to structurally qualify the modified component. Components which have been modified are identified on pages 2-64 and 2-65 of the PUSAR and include the following: feedwater nozzle, recirculation inlet nozzle, control rod drive (CRD) hydraulic system return nozzle, in-core penetration, in-core housing, intermediate range monitor (IRM) and source range monitor (SRM) dry tube, jet pump instrumentation seal, power range detector dry tube, and the vent and spray head. The editions and addenda of the ASME Code used to qualify these components, as modified, are also outlined on pages 2-64 and 2-65 of the PUSAR.

The licensee's evaluation of the RPV structure and its support components was presented in two separate portions. In the first portion, the licensee stated that certain components will experience no increase in flow, temperature, reactor internal pressure difference (RIPD) loads, or other mechanical loads as a result of EPU implementation. For these components, the licensee stated that no further structural evaluation was performed on the components given that the stresses and fatigue in these components would be unaffected, based on the absence of any appreciable change in the aforementioned parameters. Furthermore, the licensee stated that certain components did not require additional evaluations and were structurally qualified for EPU conditions based on the dispositions outlined in the CLTR, ELTR1, and ELTR2.

Based on the above, the licensee concluded that the following components did not require further structural evaluations for EPU implementation: RPV main shell, RPV main closure flange, flange closure studs, the RPV support skirt, top-head lifting lug, RPV steam water interface, liquid control delta-P nozzle, CRD penetration, CRD housing, in-core penetration, in-core housing, feedwater sparger brackets, IRM and SRM dry tube, jet pump instrumentation penetration seal, power range detector dry tube, vent and head spray, shroud support, core spray nozzle, core spray bracket, vibration instrumentation nozzle, RHR-low pressure coolant injection (LPCI) nozzle, CRD hydraulic system return nozzle, top head nozzles, refueling bellows, stabilizer bracket, jet pump instrumentation nozzle, drain nozzle, and water level instrumentation nozzle. In its February 23, 2011, response to an RAI, in which the NRC staff requested the licensee to specify the provisions used to disposition these components, the licensee detailed the dispositions used for each component and confirmed that it had used NRC staff-approved methods in determining the dispositions applicable to these components. Based on the above, the licensee confirmed that these components will continue to meet the structural design acceptance criteria applicable to each component following EPU implementation at GGNS.

The jet pump riser pads, and high and low pressure seal leak detection nozzles were not considered in the structural evaluations performed by the licensee to support EPU implementation at GGNS due to the fact that these components were not identified as RCPB components during the evaluations performed for OLTP conditions. The licensee also notes in the PUSAR that the steam dryer support bracket, hold-down bracket, and guide-rod bracket were evaluated concurrent with the structural evaluation of the new steam dryer, which is being installed in support of EPU implementation at GGNS. The NRC staff's assessment of the structural evaluation performed for these components is included in Section 2.2.6 of the SE.

The second portion of the licensee's EPU evaluation of the structural integrity of the RPV structure and support components focused on those components which could not be dispositioned as unaffected by EPU implementation at GGNS. These components (termed as limiting components in the PUSAR) are identified in Table 2.2-7 as the feedwater nozzles, main steam outlet nozzles, and the reactor recirculation system (RRS) inlet and outlet nozzles. For these components, the licensee reconciled the stresses and fatigue usage factors in the limiting components to reflect the effects of EPU implementation on the design, normal, upset, emergency, and faulted loading conditions, as applicable, to the existing stress analysis of each component to determine whether the stresses and fatigue usage factors would continue to satisfy the applicable acceptance criteria following EPU implementation. The stress reconciliation was performed by scaling the original stresses in the component evaluations based on whether the component was affected by an increase in the governing parameters (i.e., pressure, temperature, and flow) due to EPU implementation. Increases in AP, jet reaction, pipe restraint, and fuel lift loads were also included in the stress reconciliations if these loads were applicable to the component under evaluation. As indicated on pages 2-65 and 2-66 of the PUSAR, the design, emergency, and faulted loading conditions are unaffected by EPU implementation. As such, the licensee's evaluation focused on the effects of EPU implementation on the normal and upset loading conditions.

The results of the licensee's structural evaluations of the limiting components, described above, are located in Table 2.2-7 of the PUSAR. Table 2.2-7 includes a comparison of the CLTP stresses and EPU stresses to the applicable allowable stresses for each component, with the licensee noting (Note 3 to Table 2.2-7) that the evaluations were performed at a value equal to 102 percent of the proposed EPU power level. The results outlined in the table demonstrate that all of the stress limits applicable to the limiting components will continue to be satisfied at EPU conditions, with most components exhibiting minimal or no stress increases. The licensee notes that the feedwater nozzles are qualified based on an elastic-plastic analysis performed in accordance with the ASME Code provisions.

With respect to the fatigue usage factors, the results of Table 2.2-7 indicate that the low alloy steel forging of the feedwater nozzle exhibits a fatigue usage factor greater than 1.0 at EPU conditions. As such, the ASME Code criterion related to fatigue is exceeded (i.e., criteria require usage factors to be less than 1.0). However, the licensee notes that the usage factor reported is applicable only to the limiting location on the forging, which is the nozzle blend radius. Additionally, the licensee stated that the component would be qualified based on inspections performed consistent with the methods in NUREG-0619, Revision 1, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," November 1980 (Reference 97), or Revision 1 of GE-NE-523-A71-0594-A, "Alternate BWR Feedwater Nozzle Inspection Requirements," May 2000 (Reference 98). In response to an NRC staff RAI regarding the inspection provisions of these two references, the licensee stated that the inspection program for the feedwater nozzle blend radius is currently being performed in accordance with the aforementioned GE LTR. Through examinations performed at specified intervals, these inspection provisions ensure that if a thermal fatigue crack is initiated, its growth will be limited to ensure that the applicable ASME Code criteria related to the design of the nozzles will remain satisfied. Additionally, while the licensee does have inspection procedures in place to detect the aforementioned flaws, the licensee stated that it had re-performed the fatigue analysis for these nozzles based on observed (actual) corrosion rates of the nozzle. This analysis resulted in the fatigue usage factor decreasing to 0.5802 for the 40-year operating license period, which satisfies the 1.0 ASME Code requirement for fatigue.

By electronic mail dated January 27, 2011 (Reference 94), the NRC staff issued two RAIs to the licensee requesting justification for a) the reported decrease in primary plus secondary stress intensity in the carbon steel replacement safe end portion of the feedwater nozzle under EPU conditions, and b) the reported decrease in fatigue usage for the stainless steel clad replacement safe end of the feedwater nozzle at EPU conditions. In its RAI response dated February 23, 2011 (Reference 6), the licensee stated that the EPU-level stresses in the carbon steel replacement safe end of the feedwater nozzle were lower than the stresses reported at CLTP conditions based on two considerations. The licensee stated that the stresses did not increase due to EPU conditions based on the circumstances of the loads imposed by the transient governing the stresses in this portion of the nozzle. Additionally, despite more governing operating conditions at EPU conditions, the licensee stated that the stresses at EPU conditions are lower than the stresses at CLTP levels due to the use of enhanced finite element analyses (FEA) performed to support the structural qualification of the component. The FEA, as the licensee stated in the RAI response, was used in lieu of the stress scaling methodologies, described above.

With respect to the evaluation of the stainless steel clad replacement safe end of the feedwater nozzle, the licensee also cited two points of justification for the decrease in fatigue usage at EPU conditions. The licensee stated that the documentation associated with the GGNS fatigue monitoring program was used in determining a more accurate number of thermal-cycle counts which were used in the transient loads incorporated into the fatigue analysis of the component for EPU conditions. The licensee indicated that the evaluation performed for CLTP conditions for this portion of the feedwater nozzle had previously considered thermal cycles several times higher, in some cases, than the actual number of these cycles which the facility has experienced. As such, the transient loads used in the fatigue evaluation of this component for EPU conditions reflect a more accurate representation of the actual plant operating history, as it is applied to the structural evaluation of the component. Additionally, similar to the carbon steel replacement safe end of the feedwater nozzle, the licensee stated that a more modern FEA was utilized in the fatigue analyses of this portion of the feedwater nozzle. The licensee stated that the use of a more modern FEA code (i.e., ANSYS Version 11.0 SP1), coupled with the more accurate transient loads, resulted in a fatigue usage value which was lower than that previously determined at CLTP conditions.

Based on the above, the licensee concluded that the RPV structure and support components will remain structurally adequate under EPU conditions. As previously stated, this conclusion is based on the following: 1) the disposition of certain components as not being subject to additional structural evaluations for EPU implementation, based on whether they are unaffected by parameter changes due to EPU implementation and whether they are specifically dispositioned by the CLTR, ELTR1, or ELTR2; 2) the limiting components all continue to satisfy the applicable stress criteria; and 3) the limiting components continue to satisfy the applicable fatigue usage factor criteria.

NRC Staff Evaluation

The NRC staff has reviewed the licensee's evaluation of the RPV structure and support components to determine whether these structures and components are structurally adequate for operation at the proposed EPU power level. The NRC staff concludes that the licensee's assessment is acceptable. With respect to the methodology used in the evaluation of the RPV structure and support components, the NRC staff concludes that the licensee's approach is acceptable based on the fact that the approach is consistent with the methodology found in the CLTR, which has been previously approved by the NRC staff. The NRC staff notes that the CLTR states that most components associated with the RPV do not experience an increase in flow, temperature, RIPDs, or other mechanical loads. As such, most components will not experience and increase in stresses or fatigue usage.

The NRC staff also notes that the licensee did not perform additional structural evaluations for a number of components based on the licensee's assertion that the dispositions outlined in the CLTR, ELTR1, and ELTR2 are applicable to the aforementioned components and, as such, no additional evaluations for the components are required and the components remain structurally qualified for EPU conditions. The NRC staff reviewed the licensee's RAI response regarding the application of the aforementioned dispositions to a number of RPV components and concluded that the licensee's application of these dispositions is acceptable based on the fact that all of the dispositions applied have been approved previously for use by the NRC staff to structurally qualify certain BWR RPV components for EPU conditions.

The NRC staff also reviewed the licensee's assessment of the limiting components, for which the licensee performed additional structural evaluations to qualify each for operation at EPU conditions. The NRC staff concludes that the licensee's methodology used to perform the structural evaluations on the limiting components acceptable, based on the fact that the licensee's approach is consistent with those methods in the CLTR and ELTR1 Appendix I, which have been previously approved for use by the NRC staff for performing structural evaluations of RPV components. The NRC staff notes that the stresses in all of the limiting components were demonstrated by the licensee as being within the allowable stress values applicable to each component. The NRC staff reviewed the licensee's justification for the stress value developed in the carbon steel replacement safe end portion of the feedwater nozzle at EPU conditions. For this component, the licensee performed an FEA in lieu of utilizing the stress reconciliation methodology used to qualify the other limiting components for EPU implementation. The NRC staff concludes that the licensee's assessment of the reconciled stresses using FEA for this portion of the feedwater nozzle is reasonable, based on the fact that using modern FEA techniques is likely to result in a more accurate representation of the state of stress in this portion of the feedwater nozzle, given that unnecessary conservatisms would be expected to exist in the CLTP stress analysis.

The NRC staff's review of the fatigue analyses performed for the limiting RPV components noted that all but one component satisfied the 1.0 fatigue usage factor acceptance criterion, with one additional component being qualified using advanced FEA techniques and insights from the licensee's fatigue monitoring program. Similar to the carbon steel replacement safe end portion of the feedwater nozzle, the NRC staff concludes that the licensee's assessment of the fatigue usage of the stainless steel clad replacement safe end portion of the feedwater nozzle using FEA is acceptable. The NRC staff concludes that the licensee's conclusion, stating that advanced FEA techniques will result in more accurate structural evaluations and is reasonable. Additionally, by considering the actual number of transient thermal-cycle loads imparted on the component, as opposed to an assumed number used in the CLTP structural analysis, the NRC staff notes that the licensee was able to show that the CLTP structural evaluation of the component considered an unreasonably large number of thermal-cycle transients, thus resulting in a higher value for fatigue usage of the component. Based on the licensee's detailed description of its use of the actual number of thermal-cycle transients encountered by the component, as opposed to using the estimate assumed in the CLTP evaluation, the NRC staff concludes that this approach acceptable.

For the low alloy steel forging portion of the feedwater nozzle, the NRC staff notes that the fatigue usage in the component, as reported in the PUSAR, was above the acceptance criterion value of 1.0 at EPU conditions. However, as indicated above, the licensee's RAI response regarding the qualification of this portion of the RPV confirmed that the licensee was able to qualify the component with a revised fatigue analysis which accounted for observed corrosion rates. The NRC staff concludes that the licensee's assessment is acceptable based on the fact that the ASME Code criterion for fatigue is satisfied for this component at EPU conditions.

Based on the above, the NRC staff concludes that the licensee has provided reasonable assurance that the structural integrity of the RPV structure and support components will be maintained following EPU implementation at GGNS, as demonstrated by the fact that a majority of the RPV components are unaffected by EPU implementation and do not require additional structural evaluations. For those components which are affected, the licensee demonstrated that the applicable acceptance criteria related to their design will continue to be satisfied following EPU implementation.

2.2.2.4 Piping and Component Vibratory Behavior

2.2.2.4.1 Piping Vibration

Vibration resulting from EPU implementation can result in a potentially higher number of cyclic loadings in pressure-retaining components. The licensee detailed its evaluation of the effects of vibration, including FIV, on the pressure-retaining components affected by EPU implementation in Section 2.2.2.1 of the PUSAR (Reference 57). As the licensee stated in the EPU LAR, Section 3.0 of Attachment 10, "Vibration Analysis and Testing Program," the mechanics of piping vibration resulting from flow and other sources (i.e., pump vane passing frequency resonance) cannot be completely characterized through analytical methods and its effects must be evaluated using a coupled approach, consisting of analytical evaluations and testing. The licensee outlined its EPU power ascension testing plan in Section 2.12 of the PUSAR and Attachments 9 ("Extended Power Uprate Startup Testing Plan") and 10 ('Vibration Analysis and Testing Program") to Reference 1. These portions of the licensee's EPU LAR submittal detail the power ascension and initial EPU operation testing plans which the licensee will utilize to verify that piping vibration levels, due to increased fluid flow at EPU conditions, will not exceed established vibration acceptance criteria. These portions of the LAR submittal also include the results of the analytical work performed by the licensee to support the EPU vibration testing plans.

In accordance with Revision 0 of SRP Section 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs" (Reference 62), the licensee performed a comparison between the tests performed during the GGNS original power ascension testing and the proposed EPU power ascension tests. As part of this comparison, the licensee identified tests performed during startup which would not be included as part of testing for EPU power ascension. With respect to piping, the licensee stated in Section 3.0 of Attachment 9 to Reference 1 that original test SU-33, "Drywell Piping Vibration," would be performed, in part, as part of EPU power ascension testing. For those portions of SU-33 which would be not be included as part of EPU power ascension testing, the licensee provided the bases for their exclusion. Regarding the exclusion of the vibration monitoring of the SRV discharge piping, the licensee stated that EPU implementation does not affect the FIV characteristics of the SRV discharge piping, based primarily on the fact that RPV pressure remains unchanged at EPU conditions and no SRV modifications or setpoint changes are necessary for EPU implementation at GGNS. Additionally, with respect to the reactor recirculation system (RRS) piping, the licensee stated that the 1.2 percent increase in core flow resulting from EPU implementation is bounded by testing performed for the RRS during the original power ascension testing, the results of which were found acceptable. As such, the licensee concluded that the original power ascension testing data for these two portions of piping within the drywell provide sufficient bases to conclude that the FIV levels within each will remain acceptable following EPU implementation.

Section 4.0 of Attachment 9 to Reference 1 presents the licensee's EPU power ascension test plan, including information regarding the vibration test plan for those portions of piping which may experience increased levels of FIV as a result of EPU implementation. As indicated in this section of Attachment 9, the licensee plans to make routine vibration measurements of affected piping systems at predetermined power levels during the ascension to ensure that affected piping does not experience vibration levels greater than the established acceptance criteria. The bases for the licensee's EPU power ascension vibration testing plan of the affected piping systems, and portions of systems, are contained in Attachment 10 to Reference 1.

In Attachment 10 to Reference 1, the licensee detailed the systems which would be monitored for unacceptable levels of FIV during ascension to EPU power levels and initial EPU operation. The licensee identified candidate systems for vibration monitoring during EPU power ascension and initial EPU operation by examining the systems at GGNS which will experience an increase in flow and, subsequently, potential increases in FIV at EPU conditions. These systems include the main steam and feedwater systems (inside and outside containment), and portions of the condensate system, extraction steam system, high pressure heater drains, low pressure heater drains and the moisture separator drain systems. Other systems are not expected to experience flow increases due to EPU implementation. The licensee stated that the vibration monitoring points for these systems were selected based on a combination of the following: 1) extrapolation of data from original power ascension testing, 2) walkdowns to identify small bore piping susceptible to FIV and 3) spectra analyses performed for the main steam and feedwater piping systems to identify limiting points of potentially unacceptable vibration at EPU conditions. For piping inside containment and inaccessible piping outside containment, the licensee will utilize accelerometers which will report data to remote data acquisition systems. Accessible piping will be monitored visually and with handheld vibration instruments to verify that vibration levels do not exceed the established displacement and/or acceleration acceptance criteria, which are discussed below.

In determining monitoring locations and vibration acceptance criteria for the main steam and feedwater piping systems, the licensee performed a uniform spectra piping analysis to characterize the main steam and feedwater steady state structural behavior which would be expected at EPU conditions. Based on the results of this analysis, the licensee identified locations which were deemed to be limiting, with respect to displacements and accelerations resulting from the vibratory loading, and also extracted the maximum alternating stresses at the limiting locations (nodes) to develop the acceptance criteria which will be used to assess the vibration during EPU testing. By letter dated February 23, 2011 (Reference 6), in response to an NRC staff RAI dated January 27, 2011 (Reference 94), regarding the specifics of the analyses performed for the main steam and feedwater piping, the licensee stated that the analyses were performed in accordance with the guidance stipulated in the 1987 Edition of the ASME "Standards and Guides for Operation and Maintenance of Nuclear Power Plants" (ASME OM-S/G Code), Part 3, "Requirements for Preoperational and Initial Start-up Vibration Testing of Nuclear Power Plant Piping Systems."

The locations which the licensee plans to monitor on the main steam and feedwater piping systems inside and outside of containment are contained in the tables of Section 5.0 of Attachment 10 to Reference 1. Regarding the absence of monitoring points on the main steam and feedwater branch piping, the licensee cited industry operating experience and its expectations that FIV levels in the main steam and feedwater piping will remain low. However, the licensee stated that any vibration levels in the main steam and feedwater piping exceeding 50 percent of the EPU allowable value will result in engineering evaluations of the branch piping connected to these systems.

For those portions of piping systems which were tested for vibration as part of the original power ascension testing, the licensee stated that the originally measured vibration levels were extrapolated to expected EPU vibration levels by increasing the original vibration levels by an amount proportional to the fluid flow velocity-squared. Using the extrapolated values, the licensee evaluated the potential for unacceptable FIV in these portions of piping systems under EPU conditions and concluded that all but one of the original locations would continue to be monitored as part of EPU implementation. The results of the licensee's evaluation indicated that eight points of the condensate system piping would require vibration monitoring as part of EPU implementation. The licensee stated that additional BOP piping outside containment would require vibration monitoring, including portions of the extraction steam and high pressure feedwater heater drain piping. While flow velocities will also increase in the feedwater heater drain piping and the moisture separator drain piping due to EPU implementation, the licensee concluded that the flow velocities in the low pressure were too low to warrant additional monitoring.

Using the guidance of the ASME OM-S/G Code, Part 3, the licensee developed the acceptance criteria which will be used for the monitoring piping systems inside and outside of containment. For the main steam and feedwater piping, the licensee utilized the steady-state vibration acceptance criterion from the ASME OM-S/G Code, which establishes an alternating stress intensity limit based on vibration loading; this criterion is denoted in Section 2.0 of Attachment 10 to Reference 1. For the BOP piping outside containment, including the condensate, extraction steam, and high pressure feedwater heater drain piping, the licensee stated that the guidance of Appendix D of the ASME OM-S/G Code, Part 3, would be utilized in establishing an acceptable vibration criterion (i.e., 0.5 inches per second). This value, the licensee stated, is established by the ASME OM Code as a safe level of vibration for any type of piping configuration. The licensee stated that piping evaluated in accordance with this criterion will require a re-analysis if the criterion is exceeded to determine acceptability of the system vibration during the EPU power ascension testing.

2.2.2.4.2 Safety-Related Thermowells and Probes

In addition to the evaluation of EPU-induced vibration in affected piping, the licensee also evaluated the effects of EPU implementation on the behavior of the safety-related thermowells and probes under higher flow conditions in the main steam and feedwater systems. While the RRS will not experience an appreciable increase in flow, the licensee did include the RRS thermowell as part of its structural evaluation of all affected safety-related thermowells, with respect to FIV. In its letter dated October 10, 2011 (Reference 32), in response to an NRC staff RAI dated October 6, 2011 (Reference 99), regarding the FIV of safety-related probes at GGNS, the licensee stated that the only safety-related probe at GGNS is located in the RRS. Given that the RRS flow rate is not significantly affected by EPU implementation, the licensee concluded that the FIV evaluations performed for the RRS probe at CLTP are applicable at EPU conditions.

Section 2.2.2.1 of the PUSAR includes a summary of the licensee's evaluation of the safety-related thermowells, in which the licensee detailed the assessments performed to demonstrate that FIV would not result in a loss of structural integrity caused by fatigue failure of these components under EPU conditions. In accordance with ASME Code, Section III, Appendix N, "Dynamic Analysis Methods," the licensee evaluated the vibratory responses of the aforementioned thermowells resulting from the higher fluid flow rates in the aforementioned systems. Using the provisions of Appendix N, the licensee stated that the structural response to FIV of each component, including synchronization of vortex shedding frequency and subsequent resonance (i.e., lock-in condition), was minimal. In its RAI response dated October 10, 2011 (Reference 32), the licensee confirmed that the lock-in condition, discussed above, is not present at EPU conditions for any of the safety-related thermowells or the safety-related RRS probe.

Using an FEA developed to model the vibratory response of each thermowell, the licensee calculated the oscillating lift and drag forces to compute the vibratory stresses in each thermowell at EPU conditions. These stresses were then compared to the applicable ASME Code allowable values for alternating stress intensities. Based on its demonstration that the thermowells and probes exhibit minimal structural responses at EPU conditions and that the vibratory stresses in the safety-related thermowells will remain below the ASME Code allowable values, the licensee concluded that fatigue failure of these components due to FIV is not likely and therefore the thermowells and probes are adequate for EPU implementation.

NRC Staff Evaluation

The NRC staff concludes that the licensee's evaluation of the effects of FIV on affected piping systems resulting from EPU implementation is acceptable. This acceptance is based on the NRC staff's review of the licensee's EPU startup testing and power ascension testing plans. In accordance with the guidance provided in the CLTR and the NRC staff's SE on the CLTR, the NRC staff reviewed the scope of the licensee's EPU testing plan, the methodology used to develop the testing plan, and the acceptance criteria proposed by the licensee to justify that the FIV levels in the affected piping will remain below levels at which fatigue failure due to cyclic loading would be expected.

The NRC staff notes that the methodology proposed by the licensee for its vibration testing plan is consistent with the guidance in the NRC staff's SE regarding the CLTR, which states that 1) vibration monitors (remote sensing and handheld) should be utilized to evaluate the vibration experienced by the piping affected by EPU implementation and 2) the guidance found in Part 3 of the ASME OM-S/G Code should be utilized in developing the EPU vibration testing plan. While the revision of the ASME Operations and Maintenance Code (ASME OM Code) cited in the NRC staff's SE for the CLTR is provided as the 1997 Edition, the NRC staff concludes that the licensee's use of the 1987 Edition of the ASME OM-S/G Code is acceptable based on the fact that the licensee confirmed in its February 23, 2011, RAI response that the guidance in this portion of the ASME OM Code has remained unchanged since the issuance of the 1987 Edition through the ASME OM-2009, which encompasses the 1997 Edition of the Code.

The NRC staff concludes that the licensee's proposed scope of the piping vibrating testing plan is acceptable based on the fact that the licensee identified all systems which would experience flow increases as a result of EPU in determining which systems would be most susceptible to FIV. While the licensee excluded a portion of the systems which will experience flow increases from testing, the NRC staff concludes that this is acceptable based on the fact that some systems were previously tested at flow rates higher than those expected at EPU conditions (such as the RRS) or are not expected to see flow rates which would create unacceptable vibratory loadings. Additionally, while the licensee stated that FIV in the branch piping attached to the main steam and feedwater system was of no concern, the NRC staff concludes that this is acceptable based, in part, on the fact that the licensee indicated that it will evaluate these portions if vibration levels in the main piping of the main steam and feedwater systems approach certain thresholds. The NRC staff concludes that the licensee's extrapolation of previously recorded vibration data to determine additional locations susceptible to FIV acceptable, based on the fact that the use of historical data provides a reasonable indicator of locations which will also be susceptible to FIV at EPU conditions.

In evaluating the acceptance criteria proposed for the assessment of the piping vibration during EPU testing, the NRC staff notes that the licensee is utilizing the ASME OM Code criteria to determine whether the piping vibration remains within acceptable limits. As stated above, the NRC staff concludes that the use of this criteria is acceptable based on the fact that it is consistent with the guidance which the NRC staff has outlined previously in this SE regarding the CLTR. Based on the above, the NRC staff concludes that the use of the 1987 Edition of the ASME OM-S/G Code to develop the vibration acceptance criteria is acceptable based on the fact that it is the same criteria cited in the ASME OM Code edition deemed acceptable for use in the NRC staff's SE for the CLTR (1997 Edition).

With respect to the evaluation of the structural integrity of the safety-related thermowells and probes, the NRC staff concludes that the licensee's conclusion that these components will remain structurally adequate following EPU implementation acceptable, based on the following rationale. As stated in the Section 3.4.1 of the CLTR and Section 3.4 of the NRC staff's SE regarding the CLTR, the increase in main steam and feedwater flows due to EPU implementation requires an evaluation of safety-related thermowells and probes associated with these systems to ensure that FIV does not result in the loss of structural integrity of these components under EPU conditions. The NRC staff concludes that the licensee's use of non-mandatory Appendix N of the ASME Code, Section III, is acceptable based on the fact that the use of industry codes and standards provides a generally conservative means for evaluating the structural integrity of components such as the thermowells and probes, as herein discussed. However, the NRC staff also notes that the non-mandatory appendices of Section III of the ASME Code are not incorporated by reference in 10 CFR 50.55a and, as such, their use is evaluated on a case-by-case basis. Therefore, the acceptance of the use of non-mandatory Appendix N, as applied to the GGNS EPU, does not constitute a generic acceptance of the use of this appendix.

The NRC staff notes that the licensee's FEA performed to calculate the vibratory stresses resulting from the increased fluid flow in the main steam, feedwater, and RRS systems demonstrated that the alternating stress intensities in each thermowell are well within the ASME Code-allowable values (all calculated values maintained at least a 60 percent margin against the ASME Code allowable value). Additionally, the NRC staff notes that the licensee's RAI response dated October 10, 2011, confirmed that the RRS safety-related probe at GGNS has been evaluated for the effects of FIV at conditions which are essentially equivalent to those which will be present in the RRS at EPU conditions. Based on the fact that the licensee's evaluations demonstrated that the thermowells and probes will continue to satisfy established standards set forth by the ASME Code for lock-in and non-lock-in conditions, the NRC staff concludes that there is reasonable assurance that the structural integrity of the safety-related thermowells and probes at GGNS will be maintained following EPU implementation.

Conclusion

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

2.2.3 Reactor Pressure Vessel Internals and Core Supports

Regulatory Evaluation

Reactor pressure vessel (RPV) internals consist of all 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 covered (1) the analyses of flow-induced vibration (FIV) for safety-related and non-safety-related reactor internal components and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and CUFs against the corresponding Code-allowable limits.

The NRC's acceptance criteria are based on (1) 10 CFR 50.55a, "Codes and standards," 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; (2) GDC 2, "Design bases for protection against natural phenomena," insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC 4, "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; and (4) GDC 10, "Reactor design," insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of AOOs.

Specific review criteria are contained in SRP Sections 3.9.1, "Special Topics for Mechanical Components," 3.9.2, "Dynamic Testing and Analysis of Systems, Structures, and Components," 3.9.3, "ASME Code Class 1, 2, and 3 Components, and Component Supports, and Core Support Structures," and 3.9.5, "Reactor Pressure Vessel Internals" (Reference 62); and other guidance provided in Matrix 2 of RS-001 (Reference 54). The NRC staff's review also considered the guidance provided in Sections 3.3 and 3.4.2 of the CLTR (Reference 55), which contain NRC staff-approved methodologies for evaluating the effects of EPU implementation on RVIs and core support structures and the effects of FIV on these components, respectively. The SER enclosed with the CLTR documents the NRC staff's review and approval of these methodologies, including any limitations on the use of the CLTR.

Technical Evaluation

The licensee provided the results of its evaluation of the effects of EPU implementation on the RPV internals, including core support structures and non-core support structures, in Section 2.2.3 of the PUSAR. The evaluation performed by the licensee included a determination of the effects of FIV on the RPV internals resulting from EPU implementation and a separate, structural evaluation detailing the effects of EPU implementation on the design-basis loads which govern the structural behavior of the RPV internals. Additional consideration was given to the effects of EPU implementation on the loads resulting from reactor internal pressure differences (RIPDs), which increase due to the increased steam flow resulting from EPU implementation (see Section 3.3.1 of the CLTR). The design-basis information related to the RPV internals is located in GGNS UFSAR Sections 3.9.3, 3.9.5, 4.1.2, and 4.5.2.

2.2.3.1 Flow-Induced Vibration Evaluation

Section 2.2.3.1 of the PUSAR (Reference 57) details the scope, methodology and results of the licensee's assessment of the effects of EPU implementation on the FIV of the GGNS RPV internals. This evaluation is performed to ensure that SSCs which are susceptible to high-cycle loading, resulting from FIV, remain structurally adequate against the effects of FIV following EPU implementation. The licensee's evaluation was divided into two primary portions; RPV internals whose FIV behavior is primarily dependent on the core flow rate and RPV internals whose FIV behavior is dependent on other parameters, such as steam flow, feedwater flow, and recirculation drive flow.

For the former set of internals, the licensee indicated that FIV governed by core flow only affects the in-core guide tube and control rod guide tube components. Table 1-2 of the PUSAR indicates that the maximum core flow rate does not change as a result of EPU implementation. As such, the licensee concludes on page 2-70 of the PUSAR that the stresses induced in these components due to FIV do not increase as a result of EPU implementation, given that the maximum value of the parameter governing these stresses (core flow) does not increase as a result of EPU. Furthermore, the licensee notes that the analyzed FIV stresses currently induced in these components, which are the stress levels at which these components are expected to remain following EPU implementation, are well within the applicable acceptance criteria.

For those RPV internals not susceptible to increased FIV stresses resulting from increased core flow, the licensee noted that the increase in power level may increase RPV internals vibrations due to the increase in feedwater, steam and recirculation pump drive flow. The RPV internals which were evaluated for the effects of the aforementioned increased flow are outlined as items a) through o) in Section 2.2.3.1.2 of the PUSAR; this list includes the steam dryer, which is evaluated separately in the PUSAR in support of EPU implementation at GGNS. This evaluation was performed at a power level equal to 102 percent of the requested EPU power level and 105 percent of the rated core flow value. The analytical evaluation employed by the licensee to evaluate the FIV stresses on these components relied on extrapolating previously recorded vibration measurements at prototype plants, or similar plants, to obtain expected vibration amplitudes of each component at EPU conditions. Once the expected vibration amplitude was obtained for each component, the licensee then compared the expected value with the established vibration acceptance criteria to determine whether each component would maintain its structural integrity against the effects of FIV at EPU conditions.

A synopsis of the analyses performed for each component begins on page 2-69 of the PUSAR. The summaries include detailed comparisons of the limiting structural conditions induced in each component, due to FIV at EPU conditions, with the applicable acceptance criteria. Based on the evaluation results, the licensee concluded that all RPV internal components either maintain adequate margin against the established FIV acceptance criteria or are affected negligibly by FIV at EPU conditions.

As indicated in SE Section 2.2.2.4, the licensee developed an EPU startup testing plan which includes provisions for monitoring the potential for unacceptable FIV in structures during the ascension to the proposed EPU power level. The licensee noted in Attachment 9 to Reference 1 that test SU-34, performed as part of the original power ascension testing at GGNS, included the monitoring of certain RPV internals for potentially unacceptable levels of FIV. As indicated in Section 3.17 of Attachment 9, the testing performed for RPV internals susceptible to FIV due to core flow rate was done at conditions which are more limiting than those which will be realized at EPU conditions (i.e., higher core flow rates than EPU core flow rate). The vibration levels measured during the original power ascension testing were deemed satisfactory for these internals. As such, this testing will not be included as part of EPU power ascension testing based on the fact that the original testing conditions bound the conditions expected under EPU conditions.

NRC Staff Evaluation

The NRC staff concludes that the licensee's evaluation of the effects of FIV on the RPV internals is acceptable. The NRC staff notes that the licensee considered all regions of the RPV in identifying the scope of the RPV internals FIV evaluation, including the lower plenum, core region, and other regions of the RPV containing internals which are susceptible to FIV; this scope is consistent with the NRC-approved guidance outlined in Section 3.4.2 of the CLTR. With respect to those RPV internals for which FIV is governed primarily by core flow rate, the NRC staff notes that Table 1-2 of the PUSAR shows that the maximum analyzed core flow rate does not increase as a result of EPU implementation at GGNS. Therefore, the NRC staff concludes that there is reasonable assurance that these components will maintain their structural integrity against failure due to FIV, given that they have been previously evaluated at core flow values which bound or are equal to those expected at EPU conditions.

The NRC staff also notes that the licensee performed a plant-specific evaluation for those components whose FIV behavior is affected by an increase in feedwater, recirculation drive and/or steam flow. The plant-specific evaluation approach, using extrapolations of relevant vibration data and dynamic analyses of certain internals, is consistent with the guidance found in the CLTR and the NRC staff's corresponding SER related to the CLTR and, therefore, the NRC staff concludes that this approach is acceptable. Furthermore, based on the licensee's demonstration that the evaluations performed resulted in all RPV internals satisfying applicable vibration acceptance criteria, the NRC staff concludes that the licensee's conclusion, that the RPV internals evaluated on a plant-specific basis will retain satisfactory behavior against the effects of FIV under EPU conditions is acceptable.

With respect to the exclusion of certain RPV internals from EPU power ascension testing, the NRC staff notes that the licensee has previously evaluated the FIV of RPV internals impacted by core flow at conditions which bound those which will be experienced at EPU conditions, as part of the licensee's original power ascension testing. Additionally, the NRC staff notes that the results of the original testing were deemed satisfactory and, as such, the NRC staff expects that the levels of FIV would continue to remain satisfactory if testing were re-performed as part of EPU power ascension. Based on the above considerations, the NRC staff concludes that there is reasonable assurance that those RPV internals susceptible to FIV will maintain adequate structural margin against failure due to high-cycle loadings resulting from FIV.

2.2.3.2 Design Loads Evaluation

In addition to the evaluations performed to demonstrate the structural integrity of the RPV internals against fatigue failure due to FIV, the licensee also performed an assessment of the effects of EPU implementation on the design-basis loads and loading combinations used to structurally qualify the RPV internals. This assessment is documented in Section 2.2.3.2 of the PUSAR (Reference 57) and includes an evaluation of the effects of EPU implementation on the core support structures and non-core support structures at GGNS, which together comprise the RPV internals. In evaluating the structural adequacy of the RPV internals at EPU conditions, the licensee stated in the PUSAR that the RPV internal components were evaluated consistent with the applicable design-basis methodologies and acceptance criteria used in the structural design of the RPV internals. As indicated in Section 3.9.5.2.1 of the GGNS UFSAR, the core support structures at GGNS were designed and analyzed in accordance with Subsection NG of the ASME Code, Section III, "Core Support Structures." While the PUSAR indicates that the non-core support structures are not ASME Code components, the design and analyses of these components was also performed in accordance with the provisions of the ASME Code.

The licensee's methodology for structurally qualifying the RPV internals for EPU conditions is outlined in the aforementioned PUSAR section. This methodology relies on determining the stresses in the RPV internals at EPU conditions by linearly scaling the critical or governing stresses within each component, based on the magnitude of the increase in the loads which make up the design-basis loading combinations for each of the RPV internals. The increase in the magnitude of a particular load is based on the determination of whether EPU implementation results in an increase (or decrease) in a certain parameter which governs the loads. The loads considered in the evaluation of the RPV internals include those due to deadweight loads, seismic-induced loads, reactor internal pressure differences (RIPDs) loads, SRV loads, LOCA-induced loads, AP and jet reaction loads, thermal loads, flow, acoustic and FIV loads due to a postulated recirculation line break accident, and fuel lift loads.

Additional consideration was given to the loading contribution on the RPV internals due to the change in RIPDs resulting from EPU implementation. As indicated in Section 3.3.1 of the CLTR and Section 2.2.3.2.1 of the PUSAR, EPU implementation results in a higher core exit steam flow, which requires the revision of the RIPD loads for the applicable loading conditions, which include the normal, upset, and faulted conditions at GGNS. The licensee summarized the comparisons of the RIPD loads at the CLTP and EPU power levels in Tables 2.2-8 through 2.2-10 of the PUSAR. In response to an NRC staff RAI dated January 27, 2011 (Reference 94), regarding whether the licensee had calculated the faulted loading condition RIPDs under the most limiting EPU conditions, the licensee confirmed in its response dated February 23, 2011 (Reference 6), that the RIPDs in Table 2.2-10 had been calculated using both normal feedwater temperature (NFWT) assumptions and reduced feedwater temperature (RFWT) assumptions, the latter referring to a feedwater heater out-of-service (FWHOOS) operational flexibility which the licensee stated is used on a limited operational basis per year. By calculating the RIPDs under both conditions, the licensee stated that the most governing RIPD loads were determined for each RPV internal. Subsequently, it was determined that a portion of the RIPDs for certain RPV internals (identified in the RAI response) were more limiting under NFWT conditions, while some RPV internals had higher RIPD loads under RFWT conditions.

With respect to the individual RPV internals, the licensee provided a detailed summary of the quantitative evaluations performed to structurally qualify each internal on pages 2-75 through 2-79 of the PUSAR, including a tabulated summary of the limiting stresses and CUFs in Tables 2.2-11 and 2.2-12 of the PUSAR. The RPV internals evaluated by the licensee in support of EPU implementation include the following: the shroud support, shroud, core plate, top guide/grid, control rod drive housing, control rod guide tube, orificed fuel support, peripheral fuel support, fuel channel, steam dryer (evaluated in a separate section of the PUSAR), feedwater sparger, jet pump assembly, core spray line and sparger, access hole cover, shroud head and separator assembly, in-core housing and guide tube, vessel head cooling and spray nozzle, and the LPCI coupling. All of the RPV internals were identified by the licensee to be in their original configuration except for the shroud head and separator assembly, which was analyzed in accordance with its permanently modified configuration. For each component, the licensee identified the loads, described above, which are applicable to the design-basis of the component and also further stated how each load was affected by EPU implementation. While these loads vary for each component, the licensee noted that loads due to deadweight and seismic-induced motion are not affected by EPU implementation (seismic qualification and seismic loads are discussed further in SE Section 2.2.5). Additionally, the summaries of the RPV internal structural evaluations note that other loads remain unchanged for certain components while certain RPV internals were evaluated with loads which continue to bound those loads which would be realized at EPU conditions.

As noted previously, the increases in the loads applicable to a particular RPV internal formed the bases for the stress reconciliations performed for each of the RPV internals. The results of the licensee's evaluations described above were presented in Table 2.2-11. This table presents the stresses for each component at the CLTP level and at the EPU level and compares each stress level to the allowable stress limit for the governing condition (i.e., normal, upset, emergency or faulted loading condition). The results presented in this table demonstrate that for a majority of the RPV internals evaluated, the governing stresses did not increase as a result of EPU implementation. For those components whose stress levels did increase as a result of the increase in one or more of the previous loads resulting from EPU implementation, the licensee demonstrated that the induced stresses at the EPU power level did not exceed the allowable stress limits applicable to each internal. In addition to evaluating the governing stresses in the RPV internals, the licensee also presented the results of the fatigue evaluations performed to demonstrate that RPV internals, whose design bases require a fatigue evaluation, will continue to maintain adequate margin against fatigue failure at EPU conditions. The results of the fatigue evaluations performed by the licensee are located in Table 2.2-12 of the PUSAR and demonstrate that EPU implementation does not result in the increase in fatigue usage of any of the RPV internals subject to fatigue evaluations. Based on the results presented in Tables 2.2-11 and 2.2-12, the licensee concluded that the RPV internals will continue to satisfy the structural design-basis requirements associated with the internals following EPU implementation at GGNS.

NRC Staff Evaluation

The NRC staff's review of the evaluation performed by the licensee to demonstrate that the structural integrity of the RPV internals will be maintained following EPU implementation at GGNS concludes that the evaluation is acceptable based on the following rationale. The methodology employed by the licensee to evaluate the loads and load combinations applicable to the RPV internals is consistent with the guidance outlined in Section 3.3 of the CLTR, "Reactor Internals." The NRC staff has previously reviewed and approved this approach in Section 3.2 of the SER documenting the NRC staff's overall review of the CLTR. The NRC staff notes that the licensee considered all loads applicable to the structural design of the RPV internals in determining what effects EPU implementation would have on these loads and the subsequent loading combinations. With respect to the seismic and deadweight loads included in the RPV internals loading combinations, the NRC staff concludes that the licensee's assumption that these loads remain unchanged by EPU implementation acceptable, given that EPU implementation does not add additional deadweight to any RPV internal nor is the seismic response spectra for any RPV internal affected by EPU implementation.

With respect to the RIPD loads considered in the licensee's structural evaluation of the RPV internals, the NRC staff notes that coupling the calculation of RIPDs with an RFWT assumption can result in a non-conservative value for the RIPDs used in the structural evaluation of RPV internals (or any component) whose design-basis loading combinations include loads due to RIPDs. The NRC staff concludes that the licensee's response to the RAI regarding the RIPD load calculation assumptions is acceptable based on the fact that the licensee evaluated RIPD values for RPV internals at both RFWT and NFWT values. By evaluating both scenarios, this approach ensured that each RPV internal was analyzed under the most limiting conditions at the proposed EPU power level.

In addition to the methodology used to structurally qualify the RPV internals for EPU conditions, the NRC staff's review placed significant consideration on the results of the structural evaluations performed for the RPV internals, which were quantified in Tables 2.2-11 and 2.2-12 of the PUSAR. The NRC staff notes that the results of the stress analyses of the RPV internals demonstrated that many of the RPV internals do not see an increase in the governing stresses when power is increased to EPU levels. Additionally, for those components which do see an increase in stresses, the applicable allowable stress values prescribed by the design Code of record continue to be satisfied at EPU conditions. The NRC staff also notes that EPU implementation does not result in the increase in any of the RPV internals cumulative usage factor (CUF) values, demonstrating acceptable performance against fatigue failure of these components under EPU conditions. Therefore, based on the fact that the licensee demonstrated that all of the structural acceptance criteria (i.e., design code-allowable values) used in the design of the RPV internals will continue to be satisfied following EPU implementation, the NRC staff concludes that there is reasonable assurance that structural integrity of the RPV internals will continue to be maintained under all applicable loading conditions following EPU implementation at GGNS.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of RPV internals and concludes that the licensee has adequately addressed the effects of the proposed EPU on the reactor internals and core supports, including the effects of FIV and the effects of EPU implementation on the design loads and loading combinations applicable to the RPV internals. 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, GDCs 1, 2, 4, and 10 following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the design of the reactor internal and core supports.

2.2.4 Safety-Related Valves and Pumps

Regulatory Evaluation

The NRC staff's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME Code and within the scope of Section XI of the ASME Code and the ASME Operations and Maintenance Code (OM Code), as applicable. The NRC staff's review focused on the effects of the proposed EPU on the required functional performance of the valves and pumps at GGNS. The review also covered any impacts that the proposed EPU may have on the licensee's motor-operated valve (MOV) programs related to NRC Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated May 2, 1989 (Reference 100); GL 96-05, "Periodic Verification of Design-

Basis Capability of Safety-Related Motor-Operated Valves," dated September 18, 1996 (Reference 101); and GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," dated August 17, 1995 (Reference 102). The NRC staff also evaluated the licensee's consideration of lessons learned from the MOV program and the application of those lessons learned to other safety-related power-operated valves. The NRC's acceptance criteria are based on (1) GDC 1, "Quality standards and records," insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 37, "Testing of emergency core cooling system," GDC 40, "Testing of containment heat removal system," GDC 43, "Testing of containment atmosphere cleanup systems," and GDC 46, "Testing of cooling water system," insofar as they require that the ECCS, 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, "Systems penetrating containment," 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), "Inservice testing requirements," insofar as it requires that pumps and valves subject to that section must meet the inservice testing (IST) program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3, "ASME Code Class 1, 2, and 3 Components, and Component Supports, and Core Support Structures," and 3.9.6, "Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints" (Reference 62); and other guidance provided in Matrix 2 of RS-001 (Reference 54).

Technical Evaluation

In its EPU LAR, 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 GGNS. This review is summarized in the following paragraphs:

In its submittal, the licensee described its review of the IST program for safety-related pumps and valves at GGNS for EPU conditions. The Code of record for GGNS is the ASME OM Code, 2001 Edition with addenda through and including the ASME OMb Code-2003. The IST program will be updated to reflect any changed test conditions or acceptance criteria. The licensee's review of affected systems revealed that the EPU conditions will have limited impacts on the IST program as follows:

- The Standby Liquid Control System (SLCS) maximum pump discharge pressure is increased by 54.3 psig [pounds per square inch gage]. This discharge pressure increase does not result in any required system modifications; however, the pressure at which the pump is tested to satisfy TS requirements must be increased and pump operation at this new pressure must be verified prior to operation at EPU conditions. As a result, the GGNS TS Surveillance Requirement and the IST Program will be updated to address the increased pressure requirement. For all other safety-related pumps, no changes in the pump testing criteria are required at the EPU conditions. Therefore, the pump designs and IST Program requirements for all other safety-related pumps are not affected by the EPU.

- EPU conditions will increase the heat load on the Fuel Pool Cooling and Cleanup System (FPCCS) during and after refueling outages because of increased decay heat. As part of the EPU, the licensee is implementing a modification to replace the FPCCS heat exchangers to restore cooling margin and post-outage flexibility. Additional relief valves required by this modification will be added to the IST program scope.

- Containment isolation valve leak rate tests (Type C tests) are performed using a calculated peak containment pressure (Pa) of 11.5 psig based on the currently licensed thermal power. From the containment analysis at EPU conditions, the peak containment pressure will increase to 11.9 psig. Due to the increase, the leak rate testing requirements for containment isolation valves will be affected by the proposed EPU. As a result, the GGNS Containment Leakage Rate Program will be updated to incorporate the new EPU P_a value.

In response to GL 89-10 and GL 96-05, GGNS established a testing and surveillance program for safety-related MOVs. The NRC closed the review of the GL 89-10 program at GGNS in Inspection Report 50-416/96-03 based on verification of the design-basis capability of safety-related MOVs. By letter dated December 11, 2000, the NRC issued an SE for the GGNS response to GL 96-05 stating that the licensee had established an acceptable program to periodically verify the design-basis capability of the safety-related MOVs (Reference 103). In its EPU LAR, the licensee described its evaluation of the MOVs within the scope of GL 89-10 and GL 96-05 at GGNS for the effects of the proposed EPU. The licensee's review of affected systems revealed that all MOVs will continue to meet their design bases and perform their safety-related functions under EPU conditions. The EPU conditions will have the following limited impacts on safety-related MOVs:

- The 480 VAC [Volts alternating current] motor control center (MCC) minimum voltages supplied from off-site power are marginally affected by EPU (0.51 VAC maximum voltage drop). This 0.11 percent voltage drop has a negligible effect on valve torque and will be incorporated into the affected MOV calculations.

- The maximum expected differential pressure (MEDP) across the four Suppression Pool Makeup (SPMU) dump valves will increase by 9.7 percent which decreases the available stem torque margin for these MOVs from 16.2 percent to 5.9 percent. Because the 9.7 percent MEDP increase was directly applied to the required stem torque change, the resulting 5.9 percent margin is conservative. The required stem torque is also affected by unseating and packing loads which will not change with the differential pressure (DP) increase. Based on the stem torque margin evaluation, no physical changes are required to these valves.

- Fifteen MOVs in five systems will experience an ambient temperature increase and a resultant increased torque effect (i.e., decreased safety margin). In all cases, however, the safety margin decrease is quite small compared to the available safety margin and for this reason no physical modifications will be required.

- Thirteen residual heat removal (RHR) system MOV actuators were identified for which the EPU total integrated radiation dose is higher than the currently qualified limits. For these actuators the motors and switches will be replaced with parts qualified for the EPU environment.

The GGNS Air-Operated Valve (AOV) Program was developed utilizing lessons learned from the MOV Program. Elements that have been successful for the MOV Program and are contained in the AOV Program include (1) design basis/functional reviews; (2) diagnostic testing to ensure proper maintenance, setup, assembly, and performance; (3) testing priority based on valve risk significance; (4) trending of valve test results; and (5) improved maintenance instructions and controls.

The AOV Program valve population includes: (1) valves within the IST program; (2) thermal generation significant valves; (3) trip critical/sensitive valves; and (4) GGNS Level 1 and 2 PRA risk-significant valves. Based on evaluations of the GGNS AOV Program, the licensee did not identify any safety-related AOVs for which the current design bases were not sufficient for EPU conditions.

In response to GL 95-07, the licensee performed evaluations and corrective actions for certain safety-related power-operated valves that were susceptible to pressure locking or thermal binding. By letter dated October 19, 2000, the NRC issued an SE for GGNS's response to GL 95-07 stating that the licensee had adequately addressed the requested actions discussed in GL 95-07 (Reference 104). The licensee performed a review of key safety-related gate valves and determined that there is no change in susceptibility to pressure locking or thermal binding as a result of the EPU. Key parameters that cause susceptibility to pressure locking are not affected by the EPU. Under EPU conditions, the susceptibility to thermal binding, in key safety-related gate valves, is not increased because the suppression pool temperature remains below 200 °F or the valves are not required to operate during any of the transients evaluated due to changes under the new EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps at GGNS and concludes that the licensee has adequately addressed the effects of the proposed EPU on these components. 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, the NRC staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of GDCs 1, 37, 40, 43, 46, and 54, and 10 CFR 50.55a(f) following implementation of the proposed EPU at GGNS. Therefore, the NRC staff concludes that the proposed EPU for GGNS is acceptable with respect to safety-related valves and pumps.

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

Regulatory Evaluation

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

Specific review criteria are contained in SRP Section 3.10, "Seismic and Dynamic Qualification of Mechanical and Electrical Equipment" (Reference 62), and other guidance provided in Matrix 2 of RS-001 (Reference 54). The NRC staff's review also considered the guidance provided in Sections 10.1, 10.2, and 10.3 of the CLTR (Reference 55), which contain NRC staff-approved methodologies for evaluating the effects of EPU implementation on the dynamic effects of HELBs, MELBs, and equipment qualification, respectively. The SE enclosed with the CLTR documents the NRC staff's review and approval of these methodologies, including any limitations on the use of the CLTR. The NRC staff notes that the CLB requirements related to the seismic classification of SSCs at GGNS is documented in GGNS UFSAR Section 3.2. For SSCs requiring formal qualification, GGNS UFSAR Section 3.10 provides the specific provisions related to the seismic and dynamic qualification of these SSCs.

Technical Evaluation

The licensee's evaluation of the effects of EPU implementation on the seismic and dynamic qualification of mechanical and electrical equipment is summarized in Section 2.2.5 of the PUSAR (Reference 57). The licensee's evaluation of safety-related electrical equipment focused on ensuring that the existing qualifications for the equipment remain adequate under normal and accident conditions following EPU implementation. To this end, the licensee stated that the existing hydrodynamic and seismic loads used in the qualification of electrical equipment remain applicable at EPU conditions. No new HELBs were required to be postulated as a result of the proposed EPU implementation at GGNS. As the evaluation described in SE Section 2.2.1.2 indicates, EPU implementation does not affect the current AOR related to the dynamic effects related to currently postulated HELBs at GGNS. The licensee confirmed in Section 2.2.5.1 of the PUSAR that qualified electrical equipment will continue to be protected from the dynamic effects associated with postulated HELBs at GGNS following EPU implementation.

Section 2.2.5.2 of the PUSAR describes the licensee's evaluation of the effects of EPU implementation on the external loadings used in the design of mechanical equipment and components, including those loads due to seismic events, jet impingement and equipment nozzle loads. The licensee confirmed that EPU implementation does not affect the plant design bases related to the seismic and geological characteristics of the facility. Similar to the discussion above regarding electrical equipment, the licensee confirmed that the existing hydrodynamic and seismic loads used in the qualification of mechanical equipment and components remain valid at EPU condition and, therefore, the qualification of these SSCs remains unaffected by EPU implementation. The licensee confirmed that the dynamic effects were minimal and, as stated above, the effects of EPU implementation on jet impingement loads are bounded by the current AOR. The effects of EPU implementation on equipment nozzle loads were also found to be acceptable, as discussed in SE Section 2.2.2.

NRC Staff Evaluation

The NRC staff has reviewed the licensee's assessment of the impact of EPU implementation on the seismic and dynamic qualification of mechanical and electrical equipment at GGNS and concludes that the licensee's assessment is acceptable, based on the following rationale. As stated in SE Section 2.2.5, the NRC staff's review of Section 2.2.5 of the PUSAR was limited to evaluating the impact of the proposed EPU on the ability of safety related equipment at GGNS being able to withstand loads due to seismic events and those resulting from the dynamic effects of postulated pipe ruptures. The NRC staff notes that implementation of an EPU at a facility, including GGNS, does not impact the ground motions which form the bases for the primary inputs to the seismic analyses performed to seismically qualify an SSC. Given that seismic inputs used in the analyses performed qualify SSCs at GGNS are not affected by EPU implementation, the NRC staff concludes that the seismic qualification of SSCs, performed in accordance with the GGNS CLB requirements, is unaffected and will remain so following EPU implementation.

With respect to the effects of EPU implementation on the dynamic qualification of electrical and mechanical equipment and components, the NRC staff's review focused on areas previously discussed throughout SE Section 2.2. As indicated in SE Section 2.2.1, EPU implementation results in a minimal impact on the dynamic effects associated with HELBs. Given that no new HELBs are postulated as part of EPU implementation at GGNS, the NRC staff's review focused on the effects of EPU implementation on the dynamic effects resulting from currently postulated HELBs. Based on the fact that the dynamic effects from currently postulated HELBS were determined to be bounded by those used in the current AOR, the NRC staff concludes that the dynamic qualification of SSCs susceptible to the dynamic effects of postulated pipe ruptures remains unaffected by EPU implementation and, therefore, acceptable. The NRC staff's review of the impact of EPU implementation on equipment nozzle loads is documented in SE Section 2.2.2 and concluded that the effects of EPU implementation on these loads is acceptable.

Based on the above, the NRC staff concludes that the seismic and dynamic qualification of mechanical and electrical equipment and components, qualified in accordance with the existing provisions outlined in GGNS UFSAR Section 3.10, will not be affected by the implementation of the proposed EPU at GGNS. Therefore, the NRC staff concludes that there is reasonable assurance that the aforementioned equipment and components will maintain their ability to perform their intended functions when subjected to design-basis loads resulting from seismic events or dynamic effects loadings resulting from postulated pipe ruptures, as applicable, following EPU implementation.

Conclusion

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

2.2.6 Steam Dryer Structural Integrity

As a part of the major modifications for EPU, the licensee has replaced the current steam dryer with an improved design. In addition, the licensee is instrumenting the steam dryer for the purpose of performing an end-to-end benchmarking of the methodologies utilized in the steam dryer qualification. The steam dryer is a component that would be subjected to FIV and high-cycle fatigue. This section of this SE provides the NRC staff's review and evaluation regarding the structural integrity of the replacement steam dryer.

Regulatory Evaluation

Plant operation at EPU conditions can result in adverse flow effects on the main steam, feedwater, and condensate systems and their components (including the steam dryer in BWR plants) from increased system flow and FIV. Some plant components, such as the steam dryer, do not perform a safety function, but must retain their structural integrity to avoid the generation of loose parts that might adversely impact the capability of other plant equipment to perform its safety functions. The NRC staff reviewed the evaluation by Entergy of potential adverse flow effects for the proposed EPU LAR at GGNS, including consideration of the design input parameters and the design-basis loads and load combinations for the GGNS steam dryer for normal operation, upset, emergency, and faulted conditions. The NRC staff's review covered the analytical methodologies, assumptions, and computer modeling used in the evaluation of the GGNS replacement steam dryer, along with plans for in-plant measurements of oscillatory pressures, accelerations, and strains in the dryer. The staff also evaluated Entergy's license commitment to use the in-plant dryer measurements to establish a GGNS-specific benchmark to confirm the predicted stresses for the replacement dryer during power ascension from CLTP to EPU conditions. The NRC staff's review also included a comparison of the resulting stresses against applicable limits.

The NRC staff reviewed the licensee's evaluation of the main steam, feedwater, and condensate system components at GGNS for potential susceptibility to adverse flow effects from EPU operation. The NRC's acceptance criteria are based on the GDC in Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, including (1) GDC 1, insofar as it requires those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that 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 to withstand the effects of earthquakes combined with the effects of normal or accident conditions; and (3) GDC 40, "Testing of containment heat removal system," and GDC 42, "Inspection of containment atmosphere cleanup systems," insofar as they require that protection be provided for engineered safety features (ESFs) against the dynamic effects and missiles that might result from plant equipment failures, as well as the effects of a loss-of-coolant accident (LOCA). SRP Sections 3.9.1, "Special Topics for Mechanical Components," 3.9.2, "Dynamic Testing and Analysis of Systems, Structures, and Components," 3.9.3, "ASME Code Class 1, 2, and 3 Components and Components Supports, and Core Support Structures," and 3.9.5, "Reactor Pressure Vessel Internals" (Reference 62), contain specific review criteria regarding the adverse flow effects. In its review, the staff also utilized NRC Regulatory Guide 1.20, Revision 3, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing," March 2007 (Reference 105).

On September 19-20, 2011, the NRC conducted an audit to review the GEH documents pertaining to the GGNS steam dryer evaluations. The audit report and follow-up RAI action items are provided in the NRC letter dated October 19, 2011 (Reference 106). By letter dated October 10, 2011 (Reference 33), the licensee submitted responses to the action items related to the audit for GGNS. On December 7, 2011, and on January 5, 2012, the NRC along with its contractors conducted interviews of selected GEH technical staff in Wilmington, North Carolina. There were also other interviews conducted by the NRC on October 14, November 4, and November 29, 2011. Further, the NRC staff conducted another audit on March 21-23, 2012, at the GEH facilities in Wilmington, North Carolina. Based on the above, the NRC staff identified areas for which additional information was needed to reach a regulatory determination and issued RAIs to the licensee by letters dated March 2, 2011 (Reference 107), June 6, 2011 (Reference 108), February 14, 2012 (Reference 109), March 21, 2012 (Reference 110), and April 18, 2012 (two letters, References 111 and 112).

The NRC staff evaluated the licensee's RAI responses dated March 30, 2011 (Reference 11), July 6, 2011 (Reference 22), October 10, 2011 (Reference 33), November 14, 2011 (Reference 35), November 25, 2011 (Reference 36), November 28, 2011 (Reference 37), February 6, 2012 (Reference 39), February 15, 2012 (Reference 40), February 20, 2012 (Reference 41), March 13, 2012 (Reference 42), March 21, 2012 (Reference 43), April 5, 2012 (Reference 44), and April 18, 2012 (Reference 46), and determined that Entergy's final approach resolves these RAIs satisfactorily.

Technical Evaluation

2.2.6.1 Steam Dryer

GGNS is a BWR plant of BWR/6 design with a Mark III containment. The original GGNS steam dryer is similar to an upgraded BWR 4/5 curved hood design and includes perforated plates placed at the inlet and outlet sides of the vane banks in order to distribute the steam flow uniformly through the vane banks. The CLTP steam velocity at GGNS is [[ ]] and the predicted EPU (115 percent OLTP or 113 percent CLTP) steam velocity is [[ ]]; these velocities are lower when compared with the velocities at Quad Cities Unit 2 ([[ ]]). The GGNS main steam line (MSL) flow velocities are as much as 3 percent lower than corresponding velocities in the Hope Creek nuclear power plant, and are about 5 percent higher than corresponding velocities in the Susquehanna nuclear power plant, both of which were granted an EPU license amendment in 2008.

Entergy has replaced the original GGNS steam dryer with a replacement steam dryer for the EPU operation. The replacement steam dryer design is based on the design of the curved hood six-bank replacement dryer used in Susquehanna Unit 1 (SSES-1), a valid prototype BWR/4 plant. The design of the prototype BWR/4 steam dryer includes several structural enhancements to increase its resistance to high-cycle fatigue. These include [[ ]]; absence of any stitch welds; use of tees to move welds away from the panel junctions; and use of an improved tie bar design. The GGNS replacement dryer design is a significantly more fatigue-resistant design than the dryer it replaces.

The GGNS replacement dryer design meets the non-prototype classification in accordance with NRC Regulatory Guide 1.20, Revision 3, as outlined by Regulatory Position 1. Both the GGNS and SSES reactor vessels have the same inside diameters, so the GGNS steam dryer design remains essentially the same as the BWR/4 prototype design. Several minor changes were made to the prototype design to match the fit and form of the original GGNS steam dryer (i.e., the number of vessel supports increased from four to six, and the skirt is lengthened by 9.5 inches). In addition, the BWR/4 prototype design is modified to lower the alternating stresses: (1) the tee connecting the inner hoods to the divider plate was made wider and thicker to reduce the resonant response of the inner hood panels by raising frequency above the main acoustic mode of the reactor vessel, and (2) several welds moved away from the high stress area.

The MSL geometric configurations are also similar for GGNS and SSES plants except for a few plant-to-plant variations such as MSL dead legs and differences in SRV standpipe geometry.

The steam dryer pressure loads for GGNS and the BWR/4 prototype plant are very similar. The presence of dead legs in SSES plant introduces higher pressure loads particularly at [[ ]]. GGNS does not have MSL deadlegs like SSES. At frequencies above [[ ]]. These differences between the prototype and GGNS loads are addressed in the GGNS Plant-Based Load Evaluation (PBLE) load definition.

2.2.6.1.1 Field Experience with SSES Steam Dryers

By letter dated July 6, 2011 (Reference 22), in response to the NRC staff's RAI 5, Entergy stated that based on the recent inspection of the SSES-1 steam dryer in 2010, changes were made in the fabrication procedures of the GGNS steam dryer. These changes include (1) more detailed procedures for grinding control and training for surface finish requirements to avoid conditions favorable to developing intergranular stress corrosion cracking (IGSCC), and (2) elimination of tack welds on lifting lug set screws. The inspection of SSES-1 did not reveal any fatigue indications.

In its letter dated February 20, 2012 (Reference 41), Entergy further stated that the recent inspection of SSES-2 steam dryer revealed a 4.5-inches long, through-wall cracking in the dryer skirt panel at the bottom of the dryer support ring where the seismic block is welded to the dryer skirt. This weld was not included in the SSES dryer analytical model. The licensee contracted General Electric-Hitachi (GEH) to perform the submodel finite element analysis (FEA) of this weld for root cause evaluation and found that the stresses alone were not high enough to cause fatigue cracking. The subsequent root cause analysis determined that the cracking was due to inadequate design of the weld and the atypical manufacturing process used for making the weld. The design did not account for the risk associated with overlapping heat affected zones (HAZ) at a corner joint tri-junction weld, and the use of fillet weld. The atypical manufacturing included poor quality workmanship, a possibility that the proper filler metal was not used, evidence of in-process cosmetic repairs, insufficient polishing of the surface, which could have introduced high residual stresses in the weld. The high residual stresses, combined with an undetected initial indication, have led to through-wall fatigue cracking. As a corrective action, in-depth training on preparation of the HAZ surface was provided to all fabrication personnel. Training was provided to all welders in following the parameters of the approved Welding Procedure Specifications. The licensee noted that this weld is eliminated in the GGNS dryer where the seismic block is welded only to the support ring and not to the skirt. In addition, the exterior face of the seismic block is rounded and its design is modified to avoid any interference between the GGNS dryer and the seismic blocks when the dryer is installed in the reactor pressure vessel (Reference 41). Based on a review of the above noted information, the NRC staff concludes that GGNS replacement dryer is not likely to experience high-cycle fatigue cracking similar to that experienced by the SSES-2 dryer.

<u>Overview of Dryer Structural Assessment</u>

For the GGNS replacement dryer stress analysis, Entergy first estimated the FIV loads acting on the steam dryer under CLTP conditions from MSL strain gage data. For this purpose, the stress analysis employs the PBLE methodology based on GGNS plant specific MSL strain gage measurements. The GEH PBLE methodology is described in Appendices B and C of the EPU

LAR (Reference 1). [[

]] Entergy showed that the replacement dryer meets the recommended factor of 2.0 (Reference 113) for the FIV loading under EPU conditions, or minimum alternating stress ratio (MASR) of 2.0 at the maximum stress location conservatively maintaining 100 percent margin compared to ASME Code fatigue stress limit of 13,600 psi (ASME Boiler and Pressure Vessel Code, Section III, Division 1, Appendix I, Subsection NG, and Section II, 2001 Edition through 2003 Addenda) at EPU conditions. In addition, the dryer stresses also satisfy the applicable ASME Code stress limits for the normal, upset, emergency, and faulted load combinations.

During the review of Entergy's replacement dryer stress assessments, the NRC staff raised several questions regarding the GEH's PBLE methodology and the finite element modeling methodologies. As stated in Section 2.2.6 of this SE, audits of the GGNS calculations and review of the subsequent RAI responses have fully resolved concerns over these issues as discussed in this SE.

To confirm its CLTP stress assessments and the EPU stress projections, Entergy decided to instrument the replacement dryer with pressure transducers, accelerometers, and strain gages. This is expected to provide a GGNS-specific benchmark of the GEH dryer stress analysis methodology and verification of the predictive methodology. Prior to EPU power ascension, the benchmark will be used to verify that the GGNS replacement dryer will indeed operate with dynamic stress level less than that allowed by the ASME Code limits. A comprehensive power ascension plan, which monitors on-dryer strains and accelerations, along with MSL strain gage signals (related to MSL internal acoustic pressure waves) and compares them to allowable limits, will be followed. A final dryer stress assessment will be made based on computed GGNS dryer loads (benchmarked against measurements) at EPU conditions. In the event allowable stress limits are exceeded, power will be lowered to a safe level where limits are met, until the source of exceedance is identified and resolved prior to resuming power ascension.

Topics related to the loads acting on the replacement dryer and its stress analysis, as well as the instrumented dryer measurements and assessments and EPU power ascension acceptance limits, are discussed next.

2.2.6.1.1.1 Flow-Induced Vibration Loads for Steam Dryer at CLTP

The basic approach used to develop the steam dryer oscillating loads is to combine MSL strain gage measurements from GGNS under CLTP conditions [[

]]. The GGNS MSL loads are an input to GEH's Plant-Based Load Evaluation (PBLE) Methodology (often referred as PBLE Method 2), which then calculates the oscillatory pressure loads over the surfaces of the GGNS stream dryer using PBLE model bias and uncertainties determined based on the [[

]]. The PBLE approach has been evaluated and accepted by the NRC staff on a plant-specific basis for its application to the GGNS replacement steam dryer and is summarized in Section 2.2.6.1.1.2.

The licensee will be instrumenting the GGNS replacement dryer so that the conservatism of the predicted results based on the application of PBLE methodology may be confirmed specifically for GGNS prior to EPU power ascension. Entergy will use two different versions of the PBLE methodologies for this confirmation: the PBLE method based on a set of measured dryer surface pressures (often referred to as PBLE Method 1) and PBLE Method 2.

It is important that the GGNS steam dryer maintains its structural integrity from various loads including those from acoustic resonances in the SRV standpipes which are expected to be excited continuously at steam flow rates and power levels between CLTP and EPU, including continuous excitation at EPU level. However, since the acoustic resonance is excited [[ ]], which is known to be a substantially weaker excitation source than the first shear layer mode observed in QC1 and QC2, the acoustic loading on the GGNS dryer is also expected to be weaker than that observed in QC1 and QC2. [[ ]]. The details of this approach are described in Appendix A, Attachment 11B of Reference 1. If the predicted results for the dryer strains at CLTP do not bound the corresponding measurements on the replacement dryer, a similar load adder approach will be used to recompute the EPU dryer loads based on instrumented dryer measurements at CLTP.

<u>Potential SRV Acoustic Resonance</u>

MSL strain gage measurements made at GGNS indicated that several acoustic modes of the SRV standpipes are excited near CLTP at frequencies ([[ ]]). Based on measurements [[ ]], and an anechoic boundary condition was imposed at the line outlet. Due to acoustic interactions between multiple SRVs and the MSL acoustics, the finite element model analysis yielded several resonance frequencies, some of which agree reasonably well with the frequencies measured at CLTP ([[ ]].

Section 3 of Appendix A, Attachment 11B of Reference 1 presents plant measurements from seven BWRs including GGNS, BWR/4 (two plants), BWR/3 (two plants), a BWR/6, and an Advanced Boiling Water Reactor (ABWR). Based on the measured Strouhal numbers (non-dimensional frequencies normalized by steam flow rate) associated with the SRV resonances observed in these plants and the flow conditions at EPU of **[[**

]]). SRV frequencies above this range are not considered because the steam velocity at EPU is not sufficiently high to excite such high frequency resonances.

As described in Section 2.2.6.1.1.2 of this SE, the originally submitted dryer loads were determined by means of the PBLE methodology based on strain gage measurements on the MSLs known as the PBLE Method 2. **[[**

]]. However, it appears from Figure 3.20 in Appendix A, Attachment 11B of Reference 1 that the onset of the higher potential resonances, which were not observed at CLTP (

]] are modeled in the GGNS load definition. The NRC staff concludes that approach is reasonable and conservative in computing the dryer load definition.

In Figure 3.20 of Appendix A, Attachment 11B of Reference 1, the licensee used the term "*Total dryer pressure load*," to represent Y-axis. In response to the NRC staff's request, the licensee explained that this term refers to **[[**

]]. The NRC staff concludes it is reasonable that the maximum loaded **[[** **]]** is selected for tracking the acoustic load amplitude due to sources in the steam lines.

Finally, the accuracy of the PBLE loads and resulting dryer strains and accelerations at CLTP conditions, which includes the frequency range of [[ ]], will be confirmed by the instrumented GGNS dryer benchmarks to be conducted prior to power ascension beyond CLTP. Any necessary adjustments to B/U over the SRV frequencies will be made after the benchmark, and updates to the projected stresses at EPU conditions will be made and compared to allowable limits.

<u>MSL Measurements during Power Ascension to CLTP</u>

Entergy's original dryer stress submission was based on GGNS MSL strain gage data measurements at CLTP conditions. Plant MSL strain gage data (proportional to internal steam fluctuating pressures) for GGNS was obtained in 2008 for high power levels, [[ ]]. The details of the measurement program were presented in Appendix G, Attachment 11B of Reference 1, and the results are summarized in Appendix A, Attachment 11B of the same reference. The measurement procedure is similar to that used in the past by several other EPU licensees and has been reviewed and approved by the NRC staff previously. Therefore, only a brief description of the MSL measurements is presented here.

The strain gage locations on the MSLs were selected to [[ ]]. Additional optimization of the measurement locations was performed to minimize the effect of [[ ]]. Low-flow signals were measured and judged to be sufficiently low but were not used to adjust the signals that were employed in determining the dryer loads.

Since the noise floor for MSL measurements was determined from the low power measurements in 2010, while the CLTP measurements were performed in 2008, the licensee was requested to explain how the conservatism is maintained in the stress analysis computations and to clarify how the noise floor level measured at high power in 2008 is ensured to be similar to that determined at low power measurements during 2010.

In Attachment 1 to its letter dated March 30, 2011 (Reference 11), the licensee responded that because the PBLE methodology does not explicitly account for the differences in the noise floor level [[ ]], the NRC staff has determined that a minimum alternating stress ratio of 2.0 be maintained between the maximum predicted alternate stress intensity results and the corresponding allowable limits. One of the stated bases for the 2.0 margin recommendation is to ensure that there is adequate margin to the fatigue acceptance criteria for cases where the subject plant noise floor is lower than the noise floor in the [[ ]]. In addition, the licensee provided comparisons between the noise floors of the measurements performed in 2008 and 2010 on GGNS dryer as well as the noise floor of [[ ]]. Based on a review of the above information, the NRC staff agrees that the noise floor for the GGNS is similar to that of BWR/4 and that the recommended stress ratio of 2.0 provides adequate margin for cases where the subject plant noise floor is lower than the noise floor in the QC2 benchmark data. The staff agrees that no additional bias adjustments are necessary.

During the primary pressurization tests at GGNS, the strain gages were checked against the plant data of static pressure. However, the internal dynamic pressure during the tests was calculated from the strain gage data using the formula for a thick walled cylinder (with closed ends) and the MSL dimensions (diameter and wall thickness). The NRC staff requested the licensee to (1) explain whether there is any variation in the wall thickness at a given strain gage location, and (2) compare the calibration factors obtained by these two different procedures to assess any bias and uncertainties in the conversion of hoop strain to pressure.

In Attachment 1 of Reference 11, the licensee explained that the pipe thickness was measured at all strain gage locations during their installation. At each location of strain measurement, eight gages were installed and the average of the eight thickness measurements was used in the strain to pressure conversion. For all but one of the locations, the wall thickness is found to be fairly uniform with a variation range of up to ±1 percent from the average. For the remaining location (third location on MSL C), [[ ]]. The NRC staff agrees that it is adequate to use the average pipe wall thickness with the averaged strain measurements.

Regarding the calibration of the MSL strain gages and the associated bias, the licensee responded that the pressure measured during the RPV hydrostatic leak test was compared with the calculated pressure using the measured strains, average wall thickness and thick-walled cylinder equation. [[ ]]. The NRC staff concludes that this approach is acceptable because it accounts correctly for the different types of strain gages used at the PBLE benchmark plant and GGNS.

Entergy and GEH submitted additional calibration information in its letter dated February 6, 2012 (Reference 39), including an explanation of the strong 30 percent bias in the nominal strain gage sensitivity factors. The 30 percent bias (which underestimates internal pressures) was first discovered during static pressurization tests conducted at the James A. FitzPatrick Nuclear Power Plant, Unit 1 (FitzPatrick). Although the bias was not known during the QC2 benchmark tests, it is implicitly accounted for in the dryer loading B/U later computed based on comparisons to on-dryer pressure measurements. GEH also provided a report from LMS International, which investigates, in a lab environment, the effects of as-installed gage configurations for MSLs, as well as for dryers. The LMS report is used to estimate revised sensitivities for previous MSL in-plant measurements.

The test results presented in Appendix G, Attachment 11B of NEDC-33601P (Reference 1) include plots of averaged time history data for the strain gage pairs at various locations. The licensee was requested to explain how the averaged time history spectra are obtained and used in the dryer load development. In Attachment 1 of its letter dated March 30, 2011 (Reference 11), the licensee explained [[

]]. The NRC staff concludes that this approach is acceptable and in accordance with the procedures used in previous EPU applications, since the licensee provided the requested information, and the staff concludes that the averaging procedure of the strain gage signals is acceptable.

Finally, the licensee intends to use on-dryer strain gages and accelerometers to verify the bias errors and uncertainties and the loading utilized in the predictive analysis. These gages are tied to high-stress regions to determine their allowable limit curves, and represent a true end-to-end assessment of the dryer stress estimation procedure.

2.2.6.1.1.2 Plant-Based Load Evaluation Methodology

The FIV loading on the GGNS dryer consists of (1) hydrodynamic forces resulting from flow unsteadiness in the reactor pressure vessel (RPV) (upstream and downstream of the dryer) and (2) acoustic loading associated with pressure waves generated inside the RPV or propagating upstream from the MSLs, including those induced by flow-induced acoustic resonances within the standoff pipes of the SRVs. Since no purely analytical method is available at present to estimate these loads, the licensee applies GEH's PBLE method.

In its submission, the licensee described the method it uses to define unsteady hydrodynamic loads acting on the GGNS replacement steam dryer. The baseline version of the PBLE (PBLE Method 1) uses as inputs dynamic pressures measured directly on steam dryers in operating BWR plants. A modified PBLE approach (PBLE Method 2) is based on using the signals from MSL strain gage arrays as in-plant measured inputs rather than direct steam dryer pressure transducer data. PBLE Method 2 has been used to estimate oscillatory loads on the GGNS steam dryer, and the on-dryer based method PBLE Method 1) will be used to update the load estimates following measurements to be made at CLTP conditions.

The PBLE method based on MSL measurements takes into account full coupling between all four MSLs and the reactor dome. For example, it accounts for the effect of wave propagation from one steam line to another through the reactor dome. In addition, [[

]]. The approach for performing PBLE from MSL pressures is summarized below.

The hoop strains measured by the strain gage groups on the MSLs are converted to pressure fluctuations inside the steam lines at two locations and are then used to determine the acoustic pressure and velocity at each MSL inlet (nozzle). Nozzle acoustic pressures and velocities are determined by separating from the measurements the upstream and downstream traveling sound waves in the MSLs. [[

]] dryer stress calculations (see Section 2.1.4.3). The NRC staff specifies a factor of 2 for all remote sensing based dryer load estimation approaches.

Following the instrumented dryer measurements to be made at CLTP conditions, Entergy will recompute the dryer surface pressures using the PBLE Methods 1 and 2. Entergy will also perform an end-to-end benchmark based on dryer strains and accelerations, establishing end-to-end bias errors and uncertainties. If the predicted results for the CLTP conditions do not bound the corresponding measurements, then the measured data will be used for power ascension as required by the license condition described in SE Section 2.2.6.6.1.

2.2.6.1.1.3 Stress Analysis at CLTP

The GGNS replacement steam dryer is manufactured from low carbon grade Type 304L stainless steel to provide resistance to IGSCC. Its yield strength at the operating temperature (550 °F) is 15,950 psi. During normal operation, the fluctuating hydrodynamic loads are expected to produce linear elastic stresses in the dryer. The alternating stresses in the dryer components are evaluated and maintained to be at low levels so as to prevent high-cycle fatigue cracking. Since the dryer is likely to have high residual stresses due to fabrication and also at the welds, Curve C in Figure I-9.2.2 of Appendix I of the ASME Code Section III, Division 1, is used for high-cycle fatigue assessment of the dryer. According to Curve C, the allowable fatigue stress limit is 13,600 psi at 10^{11} cycles.

The licensee uses a [[

]].

Field experience has shown that the frequency range of the fluctuating hydrodynamic loads causing high-cycle fatigue cracking of the steam dryer [[ ]]. In addition, the frequency of the alternating maximum peak stress intensity can be low, usually less than 1 Hz. Therefore, the licensee has performed a [[

]].

The global finite element model of the steam dryer consists of [[

]], which is evaluated below in SE Section 2.2.6.1.1.3.1. The evaluation of the time-history analysis approach employed by the licensee is provided below in SE Section 2.2.6.1.1.3.2. At the [[

]], which is evaluated below in SE Section 2.2.6.1.1.3.3.

2.2.6.1.1.3.1 Substructure

A typical BWR steam dryer has about 20 vane bundles. The licensee modeled each vane bundle with [[ ]] (beam and shell elements) so that the geometry and construction of the vane bundle can be represented with sufficient detail. [[

]] of predefined master degrees-of-freedom (DOFs). The licensee selected the master [[

]]. The staff also requested to the licensee to address if any errors are introduced in the calculated stresses because of the use of substructure analysis.

In Attachment 1 of its letter dated March 30, 2011 (Reference 11), the licensee stated that the dryer vanes are modeled with [[
]].

The licensee showed the adequacy of substructure modeling as used in the GGNS steam dryer analysis by incorporating a similar model in the FEA [[

]]. The NRC staff concludes that the substructure model for the vane bundle is acceptable.

2.2.6.1.1.3.2 Time-History Analysis Approach

The licensee performed the stress analysis in two steps; first a preliminary analysis and then a final analysis. For the preliminary analysis, it selected a [[ ]] time history of the MSL stain measurements and divides it into several shorter equal-length time segments. Then it compared the frequency content of the corresponding PBLE pressure loads for each time segment to select two time segments, one having high-pressure load in the low-frequency band and another in the high-frequency band. Then it performed the time history analysis for the two selected bands including [[

]]. From the preliminary stress analysis results, frequency bands are selected that bracket peaks in the stress and PBLE loads. Then, the [[ ]] time history is divided into overlapping time intervals of the same length as that of the time segment, and then adjusted stress for each interval is calculated using either [[
]] as described later in this SE. [[
]].

The final analyses for the selected low- and high-frequency time intervals are performed in the same manner as the preliminary analysis. [[
]]. Then the adjusted stresses for the high stress locations are estimated using either [[ ]] for each frequency shift (load case). The maximum stress for a component and load case over all intervals divided by the stress for the analysis interval represents the time interval bias factor for that component and the load case.

The predicted stress results for the GGNS steam dryer includes stress intensities at the welds. These stress intensities are [[ ]] as discussed in SE Section 2.2.6.1.1.3.3. The resulting stresses are used for fatigue evaluation. The licensee has calculated the stresses in the steam dryer under the CLTP conditions. Then, it has adjusted these stresses to estimate the stresses under EPU conditions by applying various bias errors and uncertainties as discussed in SE Section 2.2.6.1.1.5.

[[ ]] for the Calculation of Stresses Caused by Flow-Induced Vibration

The main objective of these methods is to quickly determine the change in the peak stress from the change in the measurements or PBLE loads. This can be accomplished because the FIV evaluation of a steam dryer follows a linear elastic analysis. These methods are computationally efficient and provide a nearly real-time assessment of the FIV stresses during power ascension and normal operation. These methods calculate the adjusted stress during given time intervals as a function of changes in the calculated amplitude of the frequency-domain PBLE loads, in the measured strain, or in the acceleration data. In the [[

]] was validated during the EPU application for the Vermont Yankee operating plant.

[[

]] during its EPU power ascension testing; and showed that these two methods provided comparable results. The NRC staff concludes that the use of the [[
]] is acceptable because their technical bases (linear elastic analysis) are reasonable and because Vermont Yankee and SSES successfully used them to analyze steam dryers during power ascension for the implementation of EPU operating conditions.

2.2.6.1.1.3.3 Weld Factors

For the GGNS replacement dryer, the licensee employs qualified welding processes including penetrant tests of weld passes, and destructive tests and metallurgical evaluation of the welds. The dryer design includes full penetration welds, fillet welds and partial penetration welds. The licensee applies stress concentration factors (SCFs) to the stresses calculated at the welds as recommended by ASME Code, Section III, Subsection NG. For full penetration welds, the peak stress intensity is multiplied by SCF of [[ ]]. For fillet welds and partial penetration welds, the SCF of [[ ]] is applied to the nominal stresses at the weld or the SCF of [[ ]] is applied to the peak stress intensity at the welds. For fillet welds, if the length of the weld leg is smaller than the thickness of the plate, and [[

]]. Later, this error was rectified and the licensee chose to replace some of the partial penetration welds having high stresses by full penetration welds (Reference 39).

In the GGNS replacement steam dryer, the thickness of plates was reduced near some welds resulting in thickness mismatch at those welds. Since such mismatch was not modeled in the finite element model of the dryer, its effect on the calculated stresses is accounted for by a size reduction factor, which is equal to the square of the ratio of the model thickness to the design thickness. This size reduction factor is based on a conservative assumption that all the stresses acting at the weld are bending stresses.

As discussed, the shell global model may not provide adequate resolution of stresses at the welds or may not model the local structural details at the welds or other locations and as a result the calculated stresses from submodels could be higher or lower than the stresses from global model. In such cases, submodeling may be used for more accurate prediction of the stresses.

2.2.6.1.1.3.4 Submodeling

The licensee used solid-element submodels for local regions consisting of geometric discontinuities (e.g., fillet weld) where the global model is not capable to adequately capture the geometric details of the region in determining the peak stresses. The peak stresses determined by the use of submodeling may be higher or lower than those predicted by the global model depending upon the approximations made in modeling the geometric details of a local region.

A submodel includes a small region encompassing the high stress region, which is cut out from the global model. The licensee made certain that the size of the submodel is large enough so that the changes in the stresses at the high-stress location do not affect the stresses at the cut boundaries. The licensee performed a direct-integration time history analysis of the submodel using the same time step definition from the global model. The cut boundary conditions at each time step from the global model are extracted and mapped onto the submodel. In order to determine whether the cut boundary conditions are applied correctly, the licensee first analyzed the submodel using the original global shell mesh and compared the results with the corresponding results from the global analysis.

For the submodel of a fillet weld, the analysis stress results are linearized along several paths through the weld. The licensee refined the mesh of the solid submodel until the stress results are converged to within [[ ]]; that is, the increase in stress due to mesh refinement is less than [[ ]] (Appendix E, Reference 1). Then the maximum linearized stress intensity is multiplied by a fatigue factor of [[ ]]. The ratio of the resulting stress from the submodel analysis to the corresponding stress intensity from the global analysis is referred to as stress reduction factor, and, as discussed, it can be greater than or smaller than 1.0 depending upon the modeling approximations made in the global model.

As reported in Appendix A, Attachment 11B of Reference 1, the licensee identified two local regions, namely (i) the vane bank end plate and (ii) inner hood tee weld line in the steam dryer, where geometric details were not accounted for by the global model and performs submodel analyses of these regions for estimating the stresses more accurately. [[

]].

[[

]].

[[

]]), the inadequacy of the global model to resolve the stresses accurately at a given location is addressed by the use of strength of materials approach instead of submodeling. For such an approach, the structural forces and moments across relevant cross-sections are extracted from the global finite element model and used in the closed-form formulae from the Strength of Materials or other theoretical solutions to estimate stresses more accurately at the interested locations. The SRFs for these three cases are [[ ]].

2.2.6.1.1.4 Trending and Projecting FIV Load to EPU

2.2.6.1.1.4.1 Trending and Projecting Non-Resonant Data

[[

]].

Since the broad-band pressure loading on the dryer scales with the dynamic head in the MSLs, the non-resonant data in various quadrants is trended as a function of the MSL velocity squared. The trend lines for GGNS were calculated using four test points from plant conditions 85 percent, 90 percent, 95 percent, and the average of 10 tests at 100 percent CLTP conditions. The data points for the highest steam velocity represent 10 independent sets of plant data that were obtained at CLTP conditions. [[

]].

The NRC staff examined the trending of non-resonant data and noted that, for some dryer quadrants, the trend lines underestimate the measured dryer load at power levels lower than 80 percent. The licensee was therefore requested to explain why the pressure data at lower power levels deviate from the postulated trend for some quadrants. The licensee was also requested to explain why the projected trends at EPU conditions are considered conservative, despite the large non-conservative deviations observed at lower power levels.

In Attachment 1 of Reference 11, the licensee stated that the high power level data [[

]].

The licensee also provided sample power spectra of strain gages confirming these observations. The measurements at the lower power levels were, therefore, not used for the trending calculations. The NRC staff concludes that this response is acceptable because the data obtained at high power level are more representative and are likely to provide a reliable trend of dryer load increase as a function of the power level.

2.2.6.1.1.4.2 Trending and Projecting SRV Resonance Data

The development of the dryer load at the SRV resonance frequencies entailed FEA of the steam lines and the valve standpipes to determine potential resonance frequencies, projecting the resonant acoustic pressure based on[[

]].

The determination of the potential resonance frequencies and the values of the SRV load adders have already been addressed in Section 2.2.6.1.1.1.1 of this SE. For the selection of the phase between the SRV sources (i.e., the phase between the sources positioned at MSL entrances), the licensee used the following approach.

[[

•

]].

Since the dryer loads at CLTP were determined from in-plant MSL measurements, the licensee was requested to clarify the need for SRV load adders at CLTP. In Attachment 1 of its letter dated March 30, 2011 (Reference 11), the licensee stated that using the measured MSL signals would tie the load definition to a specific phasing and position of standing wave in each MSL relative to the position of the sensors. [[

]].

The NRC staff reviewed the licensee's response and acknowledges that using the SRV load adders at CLTP conditions is needed to provide conservative loading on the dryer regions that accounts for actual and potential SRV resonances. The staff concludes that this approach is considered to produce a conservative estimate of the dryer load and will also provide conservative limit curves.

2.2.6.1.1.4.3 Combining Non-Resonant Data with SRV Resonance Load Adders

As mentioned earlier in this report, [[
]]) were selected to be included in the GGNS structural analysis. These loads were scaled and combined with PBLE acoustic loads developed from CLTP data to generate the nominal loads used in the finite element structural analysis of the dryer.

The four SRV resonance load adders were scaled [[

]] performed after completion of the structural analysis, which is addressed in SE Section 2.2.6.1.1.5.

When the steam flow is increased during EPU power ascension, the SRV resonance is likely to shift to higher resonance frequencies. For this reason, the licensee analyzed the dryer stresses for the following five different projected EPU conditions:

[[

]].

In Section 3.2.5 of GEH Engineering Report NEDC-33601P, which is included in Attachment 11B of the EPU LAR (Reference 1), the licensee compared the projected load at EPU conditions, which is used in the stress evaluation of the GGNS replacement dryer, [[

]]. The licensee was requested to substantiate the reasons for not increasing the GGNS non-resonant loading function to envelope that of the BWR/6 prototype.

In Attachment 1 of its letter dated March 30, 2011 (Reference 11), the licensee explained that for the non-resonance frequency range, it is not necessary to implement load adders because the GGNS plant measurements at CLTP conditions have captured sufficient plant-specific frequency and amplitude content to adequately determine the dryer acoustic load at frequencies other than potential SRV resonances. The licensee further stated that the differences in the acoustic loads between the original BWR/6 dryer and the GGNS replacement dryer are reflective of the different fabrication details and geometric differences of the two plants. Based on trending from GGNS and from other EPU efforts, the non-resonant loading is most reliably determined using plant data and trending. The NRC staff reviewed the licensee's response and agrees that additional increase in the broadband non-resonance loading is not necessary because the load over this frequency range is developed from plant measurements at CLTP conditions.

In addition, the NRC staff requested the licensee to confirm that, after accounting for all bias and uncertainties, the [[

The NRC staff concludes that the implementation of above two criteria ensures that the GGNS dryer design load meets or exceeds those of the comparison plants.

While the licensee explained in some detail the scaling of the peaks of the SRV load adders, the method used to determine the bandwidth of these load adders was not discussed. The licensee was therefore requested to explain how the bandwidth of the SRV load adders is determined. In Attachment 1 of its letter dated March 30, 2011 (Reference 11), the licensee explained that [[

]]. The NRC staff concludes that this approach is acceptable because the concentration of the total energy of each load adder in a narrower frequency band provides a more conservative assessment of the peak stress in the FEA.

The EPU design load of GGNS steam dryer is developed assuming that the [[ ]]. While the effects of this resonance on the dryer alternating stresses are adequately addressed in the submitted documents, the licensee did not address the effect of SRV resonance on the operability of the valves. The licensee was requested to explain the measures that will be taken to ensure safe operation of the SRVs and avoid any eventual damage such as that occurred to the SRVs of the QC2 plant.

In Attachment 1 of its letter dated March 30, 2011 (Reference 11), the licensee provided a comparison with experience at other plants. The licensee stressed the fact that the valves in GGNS would be excited by the second shear layer mode which is a much weaker excitation source than the first shear layer mode experienced in QC2 plant which destroyed several SRV valves. In addition, the EPU steam velocity in MSLs of GGNS is substantially lower than that of QC2 at EPU ([[ ]]). Therefore, the GGNS EPU resonance peaks are expected to be weaker than those of QC2. The licensee further stated that "*somewhat similar valves*" have been used in several other plants without showing any vibration damage. However, the referenced valves do not seem to be operating continuously at resonance condition. The NRC reviewed this comparison and could not find convincing evidence that the SRVs will not be damaged by their continuous exposure to acoustic resonance in their standpipes at EPU conditions.

The licensee also listed three measures which will be taken to ensure safe operation of the GGNS SRVs and avoid any damage from acoustic resonances as occurred in the QC2 plant:

(1) The MSLs and valves will be instrumented and monitored to maintain acceleration levels within acceptance limits to minimize fatigue and wear and

ensure valve operability. The MSLs in containment will be monitored with a minimum of 14 accelerometers on the piping and 12 accelerometers on four SRVs during EPU power ascension. However, the licensee does not explain which valves will be measured and how to ensure that the four measured valves will include the one which experiences the highest vibration level at EPU.

(2) Various indicators of vibration degradation will be observed during normal operation. These include steam leakage, electrical integrity and pneumatic supply make-up rates.

(3) The Dikkers SRVs of GGNS are tested and refurbished using proven procedures and experienced craft.

Finally, the licensee provided revised texts for pages 4, 11, and 15 of Attachment 10 of the EPU LAR (Reference 1) to acknowledge the requirement that acceleration acceptance limits on the main steam safety relief valves be maintained at amplitudes that will assure operability and preclude fatigue damage.

The NRC staff believes that, if all SRVs are instrumented, these measures would provide assurance that excessive vibration levels can be detected early and mitigated. However, since the licensee does not commit to monitor the vibrations of all SRVs, the licensee was requested to explain how it will be ensured that the valve with the maximum vibration level will be among those monitored. Also, the licensee was asked to explain its plan for mitigating excessive vibration (should it occur) and/or replacing the SRVs with more vibration resistant valves. In its response, the licensee referred to Attachment 10 of Reference 1. With potential for acoustic branch line resonance at EPU, the licensee performed additional evaluations in selecting monitoring points for the SRVs. A dynamic model of the SRVs was developed and included in the piping dynamic model to capture the combined dynamic response of the MSL piping and the SRVs. [[

]]. The acceleration acceptance limits for the GGNS MSL SRVs will be maintained at amplitudes that will ensure operability and preclude fatigue damage. The following measures are taken by the licensee to ensure safe operation of the GGNS SRVs and avoid any damage from acoustic resonances.

1. These valves were seismically tested at Wyle Labs in 1977, and a Dickers SRV assembly was dynamically tested in 1984. The tested valve operated normally during and after testing with no noted signs of degradation.

2. The licensee significantly increased the number of SRVs to be monitored from 4 to 14 SRVs out of a total of 20 SRVs in the four MSLs with 16 triaxial accelerometers. Considering the symmetry of the short MSLs A and D and long MSLs B and C within the drywell, the 14 SRVs chosen for vibration monitoring represent almost all of the SRVs. The Seitz solenoid design used in the GGNS SRV actuator is not known to be susceptible to vibration degradation.

3. Further, the licensee described an acceptable plan for mitigation measures for excessive vibration. If excessive vibration is observed during power ascension,

the steam dryer and FIV monitoring limits will ensure that power is reduced to a lower level where valve and dryer loads are acceptable, and the licensee will perform a detailed evaluation.

(a) If MSL strain gage data indicates the acoustic loads are of low to medium amplitude, then piping and SRV support modification would be identified to shift or eliminate the piping/SRV response mode.

(b) If MSL strain gage data indicates the acoustic loads are of high amplitude, indicative of second shear wave to be the primary cause of excessive vibration, then the licensee will (i) mitigate the acoustic loads by employing acoustic load mitigation devices upstream of the SRV branch connections, or (ii) modify the piping geometry by shortening the SRV standpipes piping and SRV support modification would be identified to shift or eliminate the piping/SRV response mode.

It should be noted that plants with SRV vibration issues at EPU also had SRV maintenance issues prior to EPU. To date, the GGNS MSL SRVs have not exhibited any unusual wear or seat leakage, or increased failure rates. The operating experience at other BWR plants indicates that the Dikkers valve, Sempress actuator, and Seitz solenoids used at GGNS did not exhibit vibration degradation and operability issues.

Based on a review of the measures taken by the licensee, the NRC staff concludes that the licensee has a comprehensive SRV vibration monitoring program plan with adequate measures in place to mitigate excessive vibration by maintaining SRV accelerations for all modes in the SRV resonance band below SRV acceptable limits.

2.2.6.1.1.5 Bias and Uncertainties and Stress Adjustments

The GGNS dryer stresses in the original submission are adjusted according to bias errors and uncertainties (B/U) associated with the (a) PBLE loads estimation procedure, (b) structural finite element modeling procedure, **[[**

]]. Instrumented replacement dryer data will be collected at CLTP conditions and used to compute updated B/U based on end-to-end comparisons of dryer strains and vibrations. These updated B/U values will be used during power ascension to EPU conditions.

[[

]] B/U, as described in Appendix B, Attachment 11B of Reference 1 and Appendix C, Attachment 11B of Reference 1. This same TransMatrix is applied to the GGNS plant in the original submission. Benchmarking data is also available for the prototype dryer, installed in the SSES plant, but is not used to adjust PBLE B/U applied to the GGNS dryer. Two sets of PBLE B/U are used – **[[**

]]. The wide-band values are reported in Table 10 of Appendix C, Attachment 11B of Reference 1 for **[[**

]]). Additionally, a convergence study was conducted on the acoustic model of the steam within the GGNS RPV and surrounding the dryer. A more detailed mesh produced higher dryer loads, which are accounted for by including a bias error to the baseline mesh used to compute dryer stresses.

During the NRC audits of Entergy and GEH (see SE Section 2.2.6, Regulatory Evaluation), several issues were raised with the PBLE QC2 benchmark and its [[ ]] and dryer loading B/U. They include: (1) overly coarse acoustic meshing of the steam space within the RPV surrounding the steam dryer, particularly between the skirt and RPV wall and between dryer vane banks, and (2) errors in the locations and sizes of the four MSL nozzles.

Entergy and GEH have addressed item (1) in the licensee's letters dated February 15 and March 13, 2012 (References 40 and 42, respectively). The licensee's letter dated February 15, 2012, shows a localized acoustic mesh convergence study which establishes that for frequencies up to [[ ]] a single layer of acoustic elements is sufficient to resolve acoustic pressures in the gaps between the dryer skirt and RPV wall, and between dryer vane banks. The results of an overall acoustic mesh density convergence study are provided in the licensee's letter dated March 13, 2012, showing that for six locations on the QC2 dryer localized dynamic pressures are indeed higher for the more finely resolved acoustic model. This finding is consistent with that based on a similar acoustic mesh convergence study conducted on the GGNS PBLE model. Since the steam space around the GGNS dryer is represented by the more finely resolved acoustic model, the use of overly coarse acoustic mesh would introduce conservative errors in the GGNS dryer analysis.

The convergence study also shows that acoustic resonances within the acoustic model are biased high in frequency with the coarse model, such that peak acoustic loads [[ ]] are shifted higher in frequency by about [[ ]]. The effects of this shifting on the end-to-end dryer stresses are unknown, but will be accounted for by the [[ ]] in the GGNS pressure loads. In addition, the licensee has maximized the loads due to [[ ]], thus providing conservative pressure loads for the GGNS dryer analysis.

In the licensee's letter dated November 14, 2011 (Reference 35), Entergy and GEH provided [[ ]] based on correcting the MSL nozzle area errors in their QC2 benchmark. The MSL location errors were found to be less than ½-inch and therefore negligible. The estimated dryer stresses were updated based on these corrections, and were found to be lower than the ASME Code limits by more than a factor of 2.0.

For finite element modeling (Item b), GEH also considers both wide-band and narrow-band errors and uncertainties, but computes them [[

]]. During the evaluation process, the NRC staff requested a clarification on the basis for the finite element model B/U. In its letter dated March 30, 2011 (Reference 11), the licensee referred to Appendix C, Attachment 11B of Reference 1, which includes the requested information. To account for differences between strain gage factors from Kyowa on-dryer strain gages (from recently conducted test at Kyowa in Japan [Reference 19]) and gage factors in published calibration sheets, GGNS considered an additional bias of -3% and uncertainty of 10.1% to FE B&Us based on SSES on-dryer strain gages. GGNS will also consider this additional B&Us during GGNS power ascension evaluations based on GGNS on-dryer strain gages.

During the NRC audits of Entergy and GEH (see SE Section 2.2.6, Regulatory Evaluation), additional issues associated with the conservatism of the finite element modeling bias were raised, including (1) potential errors in how the acoustic pressure field computed in the PBLE model is applied to the dryer structural finite element model, and (2) ignoring potential structural (and/or acoustic) loads induced on the dryer at the [[
]].

In the licensee's letter dated November 28, 2011 (Reference 37), GEH and Entergy provided an extensive demonstration of the accuracy of their approach for mapping acoustic loads onto the dryer finite element model. The load mapping is adequate everywhere except along dryer edges, where the acoustic and finite element models do not perfectly align. Some acoustic elements extend beyond the edges of sections of the finite element model (which is common in fluid-structure interaction models). While it appears that GEH has appropriately accounted for these load mapping errors, and that the loads in these regions are small, Entergy has committed to demonstrate the overall end-to-end accuracy of the dryer stress calculation procedure by instrumenting their replacement dryer. The end-to-end benchmarking of GGNS strains and vibration will verify the predictive analysis. The instrumented dryer data can be used to make adjustments to the analysis to capture the effects of any minor errors that may exist in the load mapping.

In the licensee's letter dated February 15, 2012 (Reference 40), GEH and Entergy provided an analysis of the potential [[ ]] dryer loads. Since the loads enter the dryer either structurally through the mounting points and/or acoustically through the water and steam inside the vessel, using measured MSL internal pressures is not appropriate for quantifying their magnitudes. An analysis of the SSES dryer strains at [[ ]], and of the overall MSL vibrations in the SSES and GGNS plants reveal that [[
]] are included in the updated GGNS dryer stresses, and do not lead to any violations of the ASME code stress limits. As a further confirmation of the insignificance of [[ ]], Entergy is instrumenting their replacement dryer. Measured strains and vibrations will be checked, and additional bias errors will be applied in the event the [[ ]] are higher than expected.

When selecting [[

]], ensuring conservative dryer loads.

Since GGNS MSL data has been measured up to CLTP conditions, and not at EPU conditions, [[

]].

2.2.6.1.1.5.1 Stress Ratios at EPU

The various B/U are then used to adjust the calculated dryer stresses in four ways to ensure the worst-case stresses are used to assess potential fatigue cracking in the dryer.

(1) [[

]]

Different dryer components are projected to have their highest stress conditions using the different methods. However, most components have highest stresses when applying method 1. Based on the worst-case adjusted stresses, the GGNS dryer is projected to have a margin of safety against fatigue cracking with MASR of [[

]]. Since all of these ratios are above the recommended minimum value of 2, the NRC staff concludes they are acceptable.

<u>Reanalysis of Dryer</u>

In the original dryer stress analysis, several deficiencies in the acoustic finite element model were addressed by applying correction factors to the stresses at EPU. In mid-2011, the licensee reanalyzed the dryer by incorporating the corrections directly in the acoustic finite element model so that the additional correction factors would be unnecessary. In addition, the licensee found several discrepancies between the as-designed and as-analyzed dryer: difference in the dryer support ring dimensions, differences in steam line nozzle areas, vane passing frequency loading, and uncertainty in differential pressure data. In addition, structural finite element model was modified to include four lifting rods and collar sets. Based on the preliminary analysis results, the thickness of the lifting rod collars was increased from 0.5-0.75 inches so that the collars have lower stresses. The reanalysis results show that the MASR value of [[ ]] for the inner outlet end plates with significant margin of safety against fatigue cracking.

In its letter dated February 20, 2012 (Reference 41), in response to RAI 8, the licensee identified some nodes that were supposed to be connected were not connected. The NRC staff requested the licensee to evaluate the impact of these unconnected nodes. Twenty-four pairs of these nodes were at two locations in the divider plate-to-perforated plate interconnections. After the 24 pairs (12 pairs each at 2 different locations) of disconnected nodes were corrected, the licensee reanalyzed the global model using the nominal pressure loads. In this reanalysis, the multi-point constrain approach was applied at the shell-to-solid transition. The reanalysis results showed maximum increase of 4.93 percent in stress intensity, but no increase in the limiting component stress. Another eight pairs of unconnected nodes were identified at different locations in the global model; none of them were located at the corner or adjacent to one another. Based on the stress changes due to connecting the 12 pairs of unconnected nodes at two different locations, connecting the remaining eight pairs would not significantly impact the stress results in any components in the controlling locations (see the licensee's letter dated February 20, 2012, in response to RAI 8a; Reference 41).

To address the concern raised by the fatigue cracking at the SSES dryer, which is discussed in SE Section 2.2.6.1.1, the licensee also reviewed the finite element model for the GGNS replacement dryer by comparing it to the 3-D computer-aided design model and design drawings to identify any potential areas where the modeling did not explicitly include consideration of details in the design. This review identified two such areas where the thickness of plates was reduced near some welds resulting in thickness mismatch at those welds. Since such mismatch was not modeled in the finite element model of the dryer, the licensee accounted for its effect on the calculated stresses by applying a size reduction factor, which is discussed in SE Section 2.2.6.1.1.3.3. The [[

]] (see the licensee's letter dated February 20, 2012 (Reference 41)).

To confirm all of the uncertainties regarding the PBLE dryer loads in the GGNS predictive analysis (based on QC2 benchmarking), Entergy has elected to instrument its GGNS replacement dryer extensively with strain and vibration sensors, as well as pressure sensors. Responses to RAI 9 in the licensee's letters dated February 15 and March 13, 2012 (References 40 and 42, respectively), describe the planned instrumentation, measurements, and new benchmarking. [[

]]. The structural sensor locations have been placed strategically near, but not on, high stress regions throughout the dryer, and will be used to monitor allowable stress limits during power ascension.

At CLTP conditions, Entergy and GEH will perform an end-to-end benchmark of the strains and vibrations, along with the surface pressures. Updated B/U will be computed, and if the measured GGNS dryer stresses are found to be greater than those in the initial submission, new GGNS-specific loads computed using the PBLE method 1 (based on dryer pressure measurements) will be applied to the GGNS dryer finite element model, and the structural stress analysis repeated prior to power ascension to EPU conditions. If the originally simulated dryer stresses are conservative, GEH will use the originally simulated stresses as a baseline, applying their [[ ]] during power ascension to continually update and monitor dryer stresses. More details on power ascension are provided in Section 2.2.6.3.

2.2.6.1.1.6 Acceptance Limits (Appendix F)

In Appendix F, "Power Accession Test Plan," of Attachment 11B of Reference 1, the licensee presents the power ascension limit curves for the GGNS replacement dryer. These curves are based on the dryer pressure loads instead of the individual MSL strain measurements. This provides a direct comparison of dryer design loads with projected loads from plant data. This approach also eliminates the need to develop alternate sets of MSL power ascension limit curves to address the potential that a symmetrically located SRV resonates instead of the one assumed in the analysis.

In Section F.2 of Appendix F of Attachment 11B of Reference 1, the licensee imposes three criteria to ensure that the allowable stress limits are not exceeded for all [[ ]] during power ascension. These are the (i) maximum projected acoustic load, [[ ]]. The licensee was requested to provide a procedure for determining these criteria.

In Attachment 1 to a letter dated March 30, 2011 (Reference 11), the licensee provided [[

-

Maintaining the dryer loads below the acceptance limits assures that the FIV peak stress amplitude on the GGNS replacement dryer will remain below the ASME code endurance limit. The NRC staff concludes that this detailed description of the procedure adequately explained the process regarding the development of acceptance limits.

In Section F.2 of Appendix F, Attachment 11B of Reference 1, the licensee evaluated the dryer stress response for each of the [[

]]. The licensee provided the following explanation in a letter dated March 30, 2011 (Reference 11). Because of the differences in SRV standpipe length, as well as the interaction between the acoustics in the SRV standpipes and the MSLs, a wide spread of SRV acoustic resonance frequencies has been observed in seven GE BWRs. [[

]] This will assure that the dryer load will be acceptable if additional combinations of two or more SRV resonance frequencies occur during power ascension. The licensee further stated that at each power ascension plateau, the data trending will be updated using the projected dryer loads from the current power level. The data and plots will be reviewed to identify frequency bands that appear to be related to an SRV resonance and the dryer loads will be projected to the next test plateau to determine if there is adequate margin to the Level 1 limits to proceed with power ascension. This process will ensure that Entergy adequately addresses any observed combination of SRV resonance that could challenge Level 1 limit before proceeding with power ascension. The NRC staff concludes that the considerations for SRV resonances by the licensee is reasonable and, therefore, acceptable. The licensee's analysis adequately considered the experience from the operating fleet as well as GGNS.

2.2.6.2 Power Ascension Test Plan

The EPU Startup Test Plan is described in Attachment 9 of the EPU LAR (Reference 1), and the licensee's revision submitted as Attachment 1 to its letter dated March 13, 2012 (Reference 42). For implementation of the EPU at GGNS, Entergy will conduct a comprehensive startup testing to demonstrate the safe operation of the plant. The required modifications to support the EPU will be installed by the licensee during the 2012 refueling outage. EPU power increases will be made in predetermined increments of ≤ 5 percent power starting at 90 percent CLTP so that system parameters can be projected to EPU power. Steam dryer performance will be confirmed to be within limits by determination of steam moisture content during power ascension testing. Vibration monitoring of main steam, feedwater, and other balance of piping will be performed to assess the effect of EPU on piping. A detailed discussion of the analysis and testing program undertaken by Entergy to provide assurance that unacceptable FIVs are not experienced at GGNS due to EPU implementation for the affected piping systems is provided in Attachment 10 of the EPU LAR (Reference 1). NRC Regulatory Guide 1.20, Revision 3 (Reference 105), provides guidance and information for evaluating the potential adverse flow effects from pressure fluctuations and vibrations in piping systems for BWR nuclear plants.

Entergy provided an overview of the GGNS EPU Power Ascension Test Plan or Program (PATP) in Appendix F of the EPU LAR (Reference 1). The purpose of EPU test program is to demonstrate that SSCs will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with the design criteria at EPU conditions. The program describes plans for the initial approach to verify plant performance at EPU, needed transient testing, and the test program's conformance to 10 CFR Part 50, Appendix B, Criterion XI related to the establishment of test program to demonstrate the satisfactory performance of the SSCs in service. The three main elements of the PATP are: (1) a slow and deliberate power ascension with defined hold points and plateaus allowing time for monitoring and analysis; (2) a detailed power ascension monitoring and analysis program to trend steam dryer and piping system performance; and (3) a long-term inspection program to verify steam dryer and piping system performance at EPU conditions. Relevant data and evaluations will be transmitted to the NRC staff during the power ascension. For the GGNS PATP, Entergy presented the acceptance limits or limit curves (PSDs) based on projected pressure loads on the steam dryer divided into **[[ ]]**. During the power ascension testing above CLTP, the MSL strain gage data will be used to project the dryer loads in **[[ ]]**, which are 4 quadrants in each of outer hood, skirt and end plate, and inner hood. SE Section 2.2.6.2.1.6 includes a more detailed discussion of the GGNS steam dryer level 1 and level 2 acceptance limits or limit curves for use in the power ascension. The limit curve approach was first used by Entergy for Vermont Yankee in monitoring the modified steam dryer during power ascension testing in 2006.

Monitoring during power ascension and final assessment at EPU conditions to confirm that the steam dryer stresses are within acceptable limits are included in Section 6 of Attachment 11B of the EPU LAR (Reference 1). The purpose of the PATP is to (i) provide a controlled approach to power ascension, (ii) provide startup test acceptance criteria for comparison with measured readings during power ascension, and (iii) confirm the steam dryer analyses performed for the EPU conditions. Since the licensee has elected to instrument the dryer, the acceptance criteria shall address MSL data as well as on-dryer data.

In preparation for EPU power ascension, Entergy will prepare a Startup Test Plan to include: (a) limit curves for **[[ ]]** of the steam dryer to be applied for evaluating steam dryer performance; (b) specific hold points and their duration during EPU power ascension; (c) activities to be accomplished during hold points; (d) plant parameters to be monitored; (e) inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points; (f) methods to be used to trend plant parameters; (g) acceptance criteria for monitoring and trending plant parameters, and conducting the walkdowns and inspections; (h) actions to be taken if acceptance criteria are not satisfied; and (i) verification of the completion of commitments and planned actions specified in its application and all supplements to the application in support of the EPU license amendment request pertaining to the steam dryer prior to power increase above 3898 MWt. Entergy will submit the

FIV-related portions of the EPU startup test procedure to the NRC, including the methodology for updating the limit curves, prior to initial power ascension above 3898 MWt.

The GGNS PATP will provide for power ascension monitoring and analysis to trend steam dryer and critical piping system performance. GGNS shall provide a PATP for the steam dryer testing. This plan shall include:

- Criteria for comparison and evaluation of projected strain and acceleration with on-dryer instrument data.
- Acceptance limits developed for each on-dryer strain gage and accelerometer.
- Tables of predicted dryer stresses at CLTP, strain amplitudes and PSDs at strain gage locations, acceleration amplitudes and PSDs at accelerometer locations, and maximum stresses and locations.

The PATP shall provide correlations between measured accelerations and strains and the corresponding maximum stresses. The PATP shall be submitted to the NRC Project Manager no later than 10 days before start-up.

GGNS shall monitor the MSL strain gages and on-dryer instrumentation at a minimum of three power levels up to 3898 MWt. Based on a comparison of projected and measured strains and accelerations, GGNS will assess whether the dryer acoustic and structural models have adequately captured the response significant to peak stress projections. If the measured strains and accelerations are not within the CLTP acceptance limits, the new measured data will be used to re-perform the full structural re-analysis for the purposes of generating modified EPU acceptance limits.

Under the PATP, power will be increased at a rate of no more than 1 percent CLTP per hour. Steam line strain gage and accelerometer vibration data will be collected hourly during power ascension. At every 2.5 percent CLTP plateau, MSL strain gage and accelerometer data, and moisture carryover data, will be evaluated. At every 2.5 percent CLTP plateau, on-dryer (strain gage and accelerometer) data, dryer stresses in 12 regions, and moisture carryover data will be evaluated against the acceptance criteria, plant walkdowns will be conducted, and information will be forwarded to the NRC at every 5 percent power plateau. The stress and moisture carryover criteria will have two threshold action levels, where exceedance of Level 1 criteria requires that power be reduced to a previous acceptable level and exceedance of Level 2 criteria requires that power be held at that level with a re-evaluation of the data. The Level 1 limit curves are defined as the loading that would result in reaching 100 percent of the design limit at EPU conditions. The Level 2 limit curves are defined as the loading that would result in reaching 80 percent of the design limit.

Upon completion of the power ascension to EPU, Entergy will prepare a report on the performance of the steam dryer and plant systems during the EPU power ascension. The report will include evaluations or corrective actions that were required to obtain satisfactory steam dryer performance. The report will also include relevant data collected at each power step, comparisons to performance criteria (design predictions), and evaluations performed in conjunction with steam dryer structural integrity monitoring. Entergy will forward this report to the NRC.

As described in the license conditions during EPU power ascension of GGNS, Entergy will monitor hourly the MSL strain gage data during power ascension above 3898 MWt for increasing pressure fluctuations in the steam lines. Entergy will hold the facility for 24 hours at 102.5 percent, 105 percent, 107.5 percent, and 110 percent of 3898 MWt to collect data from the MSL strain gages, conduct plant inspections and walkdowns, and evaluate steam dryer performance based on these data. Entergy will provide the evaluations performed for 105 percent and 110 percent of 3898 MWt to the NRC staff upon completion of the evaluation; and will not increase power above each hold point until 96 hours after the NRC confirms receipt of the evaluation. Entergy will also provide the evaluations performed for 100 percent of CLTP to the NRC staff and will not increase power for 240 hours to allow for review by the NRC.

If any frequency peak from the MSL strain gage data exceeds a Level 1 limit curve, Entergy will return the facility to a lower power level at which the limit curve is not exceeded. Entergy will resolve the uncertainties in the steam dryer analysis; evaluate the continued structural integrity of the steam dryer ensuring that the minimum alternating stress ratio meets the ASME Code fatigue limit; and provide that evaluation to the NRC staff. Entergy will obtain NRC approval of that evaluation prior to further increases in reactor power. In the event that acoustic signals are identified that challenge the limit curves during power ascension, Entergy will evaluate dryer loads and re-establish the limit curves based on the new strain gage data.

Entergy will monitor RPV water level instrumentation and MSL piping accelerometers on an hourly basis during power ascension above 3898 MWt. If resonance frequencies are identified as increasing above nominal levels in proportion to strain gage instrumentation data, Entergy will stop power ascension, evaluate the continued structural integrity of the steam dryer, and provide that evaluation to the NRC staff.

After reaching 102.5 percent, 105 percent, 107.5 percent, 110 percent, and 113 percent of 3898 MWt, respectively, Entergy will obtain measurements from the MSL strain gages and dryer instruments and establish the steam dryer FIV load fatigue margin for the facility, update the dryer stress report, and re-establish the limit curves with the updated load definition, and will provide the evaluations to the NRC staff. If an engineering evaluation is required because a Level 1 acceptance criterion is exceeded, Entergy will perform the structural analysis to address frequency uncertainties up to ±10 percent and assure that peak responses that fall within this uncertainty band are addressed.

Entergy will submit a report with the results of the GGNS PATP following completion of the power ascension. As part of the post EPU monitoring program, Entergy will monitor plant parameters indicative of degradation of the steam dryer or plant systems during EPU operation. For example, moisture carryover will be monitored with the results reviewed and evaluated. As MSL strain gages and accelerometers remain operable, data collection may be performed during the remainder of the operating cycle following EPU implementation. Steam dryer inspections and monitoring of plant parameters potentially indicative of steam dryer failure will be conducted as recommended in GE Service Information Letter (SIL) No. 644, "BWR Steam Dryer Integrity," dated August 30, 2006 (Reference 114), and Electric Power Research Institute (EPRI) Technical Report 1011463, "BWR Vessel and Internals Project, Steam Dryer Inspection and Flaw Evaluation Guidelines (BWRVIP-139-A)," July 2009 (Reference 115). The results of the visual inspections of the steam dryer will be reported to the NRC staff within 90 days following startup from the respective refueling outage.

The NRC staff has reviewed the GGNS PATP for its ability to provide a slow and controlled power ascension that allows for monitoring of plant data, evaluating steam dryer and system performance, and taking corrective action in the event that plant data reveal such action is appropriate. Further, the NRC staff compared the proposed license conditions described in the SE Section 2.2.6.6 for GGNS with those applied at Hope Creek, SSES, and the Vermont Yankee power ascension. The NRC staff concludes that the GGNS PATP and the applicable license conditions provide an acceptable power ascension process that is consistent with the successful approach employed at Hope Creek, SSES, and Vermont Yankee.

2.2.6.3 Steam Dryer Stresses for Normal, Upset, Emergency, and Faulted Load Combinations

In addition to the evaluation for FIV loading and high-cycle fatigue, the licensee has also evaluated the steam dryer for the normal, upset, emergency, and faulted ASME load combinations to demonstrate its structural integrity. The licensee utilized subsection NG of the ASME Code Section III for guidance. Plant specific load combinations are followed. For normal condition, the load combinations include dead weight (DW), differential static pressure (ΔP), and the FIV. The loads utilized for upset conditions include dead weight (DW), differential static pressure (ΔP), Turbine Stop Valve (TSV) Closure, SRV loads, Operating Basis Earthquake (OBE) and the FIV. The emergency condition loads include dead weight (DW), differential static pressure (ΔP), SRV loads from automatic depressurization, and the FIV. The faulted condition loads include dead weight (DW), differential static pressure (ΔP), SRV loads, Safe Shutdown Earthquake (SSE), Acoustic load (AC) from main steam line break, and the FIV.

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Based on a review of the above results, the NRC staff concludes that the results for steam dryer stress intensities are acceptable for the normal, upset, emergency, and faulted load combinations under EPU conditions because the ratios of allowable stress intensities to maximum computed stress intensities are all greater than 1.0 thus meeting the applicable code limits.

2.2.6.4 Steam, Feedwater, and Condensate Systems and Components

The NRC staff's review of steam, feedwater, and condensate system and components is covered under SE Section 2.2.2.2 of this SE. As stated in that section, the NRC staff concludes that the licensee, using the current design basis and code of record, has adequately addressed the effects of the proposed EPU on the BOP piping, pipe components and pipe supports. Based on its review, as summarized above, the NRC staff concludes that the proposed EPU does not adversely affect the structural integrity of the steam, feedwater, and condensate system and components.

2.2.6.5 Conclusions

The NRC staff has reviewed the licensee's evaluations of potential adverse flow effects on the main steam, feedwater, and condensate systems and their components (including the steam dryer) for the operation of GGNS at EPU power level subject to the license conditions in this SE. The staff concludes that the licensee has provided reasonable assurance that the flow-induced effects on the replacement steam dryer and other plant equipment are within the structural limits at CLTP conditions and extrapolated EPU conditions. The replacement steam dryer will maintain its structural integrity and will perform satisfactorily under the proposed EPU conditions because there is conservatism in the loadings considered as well as there is significant margin (100 percent) as indicated by MASR of greater than 2.0. The staff further concludes that the licensee has demonstrated that the main steam, feedwater, and condensate systems and their components (including the replacement steam dryer) will continue to meet the requirements of draft GDCs 1, 2, 40, and 42 following implementation of the proposed EPU at GGNS. Therefore, the NRC staff concludes that the license amendment to operate GGNS at the EPU conditions regarding the steam dryer is acceptable with respect to potential adverse flow effects for high-cycle fatigue as well as to withstand the ASME Code normal, upset, emergency, and faulted load combinations.

2.2.6.6 EPU License Conditions on Potential Adverse Flow Effects

2.2.6.6.1 Steam Dryer

By letter dated April 18, 2012 (Reference 46), as supplemented by letter dated April 26, 2012 (Reference 47), the licensee proposed to add the following new license condition. Accordingly, Facility Operating License No. NPF-29 would be revised to add new paragraph 2.C.(47), which would state:

(47) This license condition provides for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant structures, systems, and components (including verifying the continued structural integrity of the steam dryer) for power ascension from the CLTP (3898 MWt) to the EPU level of 4408 MWt (or 113 percent of CLTP or 115 percent of OLTP).

(a) The following requirements are placed on operation of the facility before and during the power ascension to 3898 MWt:

1. GGNS shall provide a Power Ascension Test (PAT) Plan for the Steam Dryer testing. This plan shall include:

- Criteria for comparison and evaluation of projected strain and acceleration with on-dryer instrument data.

- Acceptance limits developed for each on-dryer strain gage and accelerometer.

- Tables of predicted dryer stresses at CLTP, strain amplitudes and PSDs at strain gage locations, acceleration amplitudes and PSDs at accelerometer locations, and maximum stresses and locations.

The PAT plan shall provide correlations between measured accelerations and strains and the corresponding maximum stresses. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up.

2. GGNS shall monitor the main steam line (MSL) strain gages and on-dryer instrumentation at a minimum of three power levels up to 3898 MWt. Based on a comparison of projected and measured strains and accelerations, GGNS will assess whether the dryer acoustic and structural models have adequately captured the response significant to peak stress projections. If the measured strains and

accelerations are not within the CLTP acceptance limits, the new measured data will be used to re-perform the full structural re-analysis for the purposes of generating modified EPU acceptance limits.

3. GGNS shall provide a summary of the data and evaluation of predicted and measured pressures, strains, and accelerations. This data will include the GGNS-specific bias and uncertainty data and transfer function, revised peak stress table and any revised acceptance limits. The predicted pressures shall include those using both PBLE methods (that is, Method 1 using on-dryer data, and Method 2 using MSL data). It shall be provided to the NRC Project Manager upon completion of the evaluation. GGNS shall not increase power above 3898 MWt until the NRC PM notifies GGNS the NRC accepts the evaluation or NRC questions regarding the evaluation have been addressed. If no questions are identified within 240 hours after the NRC receives the evaluation, power ascension may continue.

(b) The following requirements are placed on operation of the facility during the initial power ascension from 3898 MWt to the approved EPU level (4408 MWt):

1. GGNS shall increase power in increments of approximately 102 MWt, hold the facility at approximately steady state conditions and collect data from available main steam line (MSL) strain gages and available on-dryer instrumentation. This data will be evaluated, including the comparison of measured dryer strains and accelerations to acceptance limits and the comparison of predicted dryer loads based on MSL strain gage data to acceptance limits. It will also be used to trend and project loads at the next test point and to EPU conditions to demonstrate margin for continued power ascension.

2. Following the data collection and evaluation at the plateaus at approximately 4102 MWt, 4306 MWt, and 4408 MWt, GGNS shall provide a summary of the data and the evaluation performed in Section b.1 above to the NRC Project Manager. GGNS shall not increase power above these power levels for up to 96 hours to allow for NRC review of the information.

3. Should the measured strains and accelerations on the dryer exceed the level 1 acceptance limits, or alternatively if the dryer instrumentation is not available and the

projected load on the dryer from the MSL strain gage data exceeds the Level 1 acceptance limits, GGNS shall return the facility to a power level at which the limits are not exceeded. GGNS shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. GGNS shall not increase power for up to 96 hours to allow for NRC review of the information.

a. In the event that acoustic signals (in MSL strain gage signals) are identified that challenge the dryer acceptance limits during power ascension above 3898 MWt, GGNS shall evaluate dryer loads, and stresses, including the effect of ±10 percent frequency shift, and re-establish the acceptance limits and determine whether there is margin for continued power ascension.

b. During power ascension above 3898 MWt, if an engineering evaluation for the steam dryer is required because a Level 1 acceptance limit is exceeded, GGNS shall perform the structural analysis using the Steam Dryer Report, Appendix A methods to address frequency uncertainties up to ±10% and assure that peak responses that fall within this uncertainty band are addressed.

4. Following the data collection and evaluation at the EPU power level, GGNS shall provide a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the GGNS-specific bias and uncertainties and transfer function. The GGNS-specific bias and uncertainties summary shall include both PBLE Method 1 and Method 2. This report shall be transmitted to the NRC within 90 days of achieving the EPU power level. Should the results of this stress analysis indicate the allowable stress in any part of the dryer is exceeded, GGNS shall reduce power to a level at which the allowable stress is met, evaluate the dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of dryer integrity at EPU conditions, shall be provided to the NRC prior to return to EPU conditions.

(c) Entergy shall implement the following actions:

1. Entergy shall revise the post-EPU monitoring and inspection program to reflect long-term monitoring of plant parameters potentially indicative of steam dryer failure; to reflect consistency of the facility's steam dryer inspection program with GE SIL 644, "BWR Steam Dryer Failure," Revision 2; and with BWRVIP-139, "Steam Dryer Inspection and Flaw Evaluation Guidelines."

(d) Entergy shall prepare the EPU PAT plan to include the following and provide it to the NRC project manager before increasing power above 3898 MWt:

1. Level 1 and Level 2 acceptance limits for on-dryer strain gages, on-dryer accelerometers, and for projected dryer loads from MSL strain gage data to be used up to 113 percent of CLTP

2. specific hold points and their duration during EPU power ascension

3. activities to be accomplished during hold points

4. plant parameters to be monitored

5. inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points

6. methods to be used to trend plant parameters

7. acceptance criteria for monitoring and trending plant parameters and conducting the walkdowns and inspections

8. actions to be taken if acceptance criteria are not satisfied

9. verification of the completion of commitments and planned actions specified in the Entergy application and all supplements to the application in support of the EPU LAR pertaining to the steam dryer before power increase above 3898 MWt

10. identify the NRC PM as the NRC point of contact for providing PAT plan information during power ascension

11. methodology for updating limit curves

(e) The key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval. Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(f) During the first two scheduled refueling outages after reaching full EPU conditions, Entergy shall conduct a visual inspection of all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 and GE inspection guidelines. Entergy shall report the results of the visual inspections of the steam dryer to the NRC staff within 60 days following startup.

(g) At the end of the second refueling outage, following the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results for NRC review and approval

(h) This license condition shall expire upon satisfaction of the requirements in paragraph (f) provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw or unacceptable flaw growth that is caused by fatigue.

Based on the above, the NRC staff concludes the license condition will provide the monitoring, evaluation, and any required prompt actions needed in response to potential adverse flow effects as a result of power uprate operation on plant SSCs. The NRC staff concludes that the license condition will verify the structural integrity of the steam dryer, including verifying the continued structural integrity of the steam dryer for power ascension from the previous CLTP (3898 MWt) to the EPU level of 4408 MWt (or 115 percent of OLTP). The NRC staff also concludes that license condition provides reasonable assurance that the steam dryer is acceptable with respect to potential adverse flow effects for high-cycle fatigue as well as to withstand the ASME Code normal, upset, emergency, and faulted load combinations.

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

Regulatory Evaluation

Environmental qualification (EQ) of electrical equipment demonstrates that the equipment is capable of performing its safety function under significant environmental stresses which could result from design-basis accidents (DBAs). The NRC staff's review focused on the effects of the proposed EPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, AOOs, 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, "Environmental qualification of electric equipment important to safety for nuclear power plants," which sets forth requirements for the qualification of electrical equipment important to safety that is located in a harsh environment. Specific review criteria are contained in SRP Section 3.11, "Environmental Qualification of Mechanical and Electrical Equipment" (Reference 620).

Technical Evaluation

In Attachment 12 of the EPU LAR, the licensee stated that all electrical equipment in the EQ program was evaluated. In its evaluation, the licensee analyzed the changes to existing normal and accident radiation doses expected when operating at the increased reactor power level under EPU conditions. The licensee used the results of the evaluation to group the equipment into three qualification groups. The first group contains equipment that remains bounded by its existing qualification levels. The second group contains equipment that will have a reduced qualification life due to the higher radiological conditions. By letter dated November 18, 2010 (Reference 2), in response to an NRC staff request for supplemental information dated November 9, 2010 (Reference 116), the licensee stated that the equipment in the second group is tracked through the maintenance program and it is scheduled to be replaced prior to the end of its qualified life. The third group contains equipment that will need to be replaced prior to EPU implementation. In Reference 2, the licensee provided further information regarding the equipment being replaced and qualification detail on the replacement equipment. The licensee provided a regulatory commitment to replace all third group equipment not qualified by analysis prior to EPU implementation. The NRC staff reviewed the EPU LAR, the supplemental information provided by the licensee, and the licensee's EQ evaluation report. In addition, the NRC staff verified that the components identified as having a reduced or depleted qualified life due to the EPU implementation will be replaced with equipment qualified in accordance with 10 CFR 50.49 for the associated environmental conditions. Furthermore, the NRC staff verified the adequacy of the qualifications for the replacement equipment.

Inside Containment

The licensee's EQ for safety-related electrical equipment located inside containment is based on main steam line break (MSLB) and/or DBLOCA conditions and their resultant temperature, pressure, humidity, and radiation consequences. The EQ also includes the environment expected to exist during normal plant operation. The NRC staff reviewed the EPU LAR and supplemental letter and verified that the pressure and humidity during accident and normal plant operation remain unchanged inside containment. The NRC staff also verified that temperature during normal plant operation remains unchanged inside containment. Furthermore, the NRC staff reviewed the revised worst case EQ enveloping accident temperature profiles graph (including HELB and LOCA conditions) provided by the licensee in its supplemental letter dated August 30, 2011 (Reference 26). Based on the above, the NRC staff determined that the post-accident peak temperature will continue to be bounded by the peak temperature conditions used in the licensee's EQ analysis.

The radiation EQ for safety-related electrical equipment inside containment is based on the radiation dose expected to occur during normal operations plus the accident dose (total integrated dose (TID)). In Attachment 12 of the EPU LAR, the licensee stated that the TID for EPU conditions were determined to affect qualification of some equipment located inside containment. The NRC staff has reviewed the list of equipment affected by the proposed EPU revised radiation TID and concluded that the affected equipment's EPU TID is bounded by its qualification TID. Furthermore, the NRC staff verified that the components that will exceed EQ prior to the end of operation at EPU conditions are included in the second qualification group. Based on the above, the NRC staff concludes that the TID for EPU conditions would not adversely affect the qualification of equipment inside containment.

Outside Containment

The licensee's EQ for equipment located inside containment is based on MSLB or other HELB conditions, whichever is limiting for each plant area and their resultant temperature, pressure, humidity, and radiation consequences. The EQ also includes the environment expected to exist during normal plant operation. The NRC staff reviewed the EPU LAR and the response to the NRC staff's RAI and verified that the pressure and humidity during accident and normal plant operation remain unchanged outside containment. The NRC staff also verified that temperature during normal plant operation remains unchanged outside containment. In Attachment 12 of the EPU LAR, the licensee stated that in some areas outside containment, post-accident ambient temperature increases slightly due to operating at EPU conditions, either from HELBs with changed conditions or due to the loss of non-safety-related heating ventilation and air conditioning post-LOCA. The NRC staff reviewed the revised worst case EQ enveloping accident temperature profiles graph (including HELB and LOCA conditions) provided by the licensee in Reference 26 and concludes that the change to the accident operating temperature will not adversely affect the qualification of safety-related electrical equipment outside containment.

The radiation EQ for safety-related electrical equipment outside containment is based on the radiation dose expected to occur during normal operations plus the accident dose (TID). In Attachment 12 of the EPU LAR, the licensee stated that the TID evaluation determined that the post-EPU radiation dose changes result in changes in existing equipment qualification status. The NRC staff reviewed the list of equipment affected by the revised radiation TID for EPU conditions and concludes that the affected equipment's EPU TID is bounded by its qualification TID. Furthermore, the NRC staff verified that the components that require replacement, due to the EPU TID being higher than the currently qualified limits, are included in the third qualification group. Based on the above, and the licensee's commitment to replace all third group equipment not qualified by analysis prior to EPU implementation, the NRC staff concludes that the TID for EPU conditions would not adversely affect the qualification of equipment outside containment.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EQ of electrical equipment and concludes that the licensee has adequately addressed the effects of the proposed EPU on the environmental conditions inside and outside containment and the qualification of electrical equipment. 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 concludes that the proposed EPU is acceptable with respect to the EQ of electrical equipment.

2.3.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The NRC staff's review 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 the loss of offsite power (LOOP) to the plant following implementation of the proposed EPU. The NRC's acceptance criteria for offsite power systems are based on GDC 17, "Electric power systems." The specific review criteria are contained in SRP Sections 8.1, "Electric Power – Introduction," and 8.2, "Offsite Power System," Appendix A to SRP Section 8.2, and Branch Technical Positions (BTPs) PSB-1 and ICSB-11 (Reference 62).

Technical Evaluation

The licensee provided the details of EPU impact on the alternating current (ac) power system in Section 2.3 of Attachment 5B, and Attachment 12, "Grid Stability Evaluation," of the EPU LAR.

2.3.2.1 Grid Stability

GGNS is connected to the transmission grid at an on-site 500 kiloVolt (kV) switchyard through a 20.9/500 kV main step-up transformer. The 500 kV offsite power source is supplied through two 500/34.4 kV station service transformers. Independently from the 500-kV lines, offsite power is also provided to GGNS via a 115-kV line through a 115/4.16 kV engineered safety feature (ESF) transformer. The primary transmission owner is Entergy Mississippi, Inc., which is a member of Entergy Electric Systems, a grid system which consists of interconnected hydro-plants, fossil fuel plants, and nuclear plants.

In Attachment 12 of the EPU LAR, the licensee presented the results of the grid stability study performed by Southwest Power Pool, the Regional Transmission Organization responsible for the electric power grid that GGNS is connected to, to evaluate the effect of GGNS's proposed EPU on grid reliability and stability. The grid events analyzed in the study were loss of the largest generator, loss of GGNS, and loss of the most critical transmission line due to fault with the unit operating at full power transfer levels. By letter dated May 5, 2011 (Reference 16), in response to an NRC staff RAI dated April 5, 2011 (Reference 117), the licensee stated that the maximum expected gross output would be 1523.5 megawatt electric (MWe) at a power factor of 0.952 under EPU conditions. According to the licensee, the study analyses were evaluated at 1544 MWe, utilized 2012 summer peak conditions, considered the use of a new generator, and included the prior-queued generation projects that could impact grid reliability and stability as a result of the proposed GGNS EPU. Also, the analyses where performed using Siemens-PTIs PSS/E™ dynamics program V30.3.2 in accordance with national and regional reliability council criteria.

In Attachment 12 of the EPU LAR, the licensee stated that in order to meet the Federal Energy Regulatory Commission regulations of proportion of megavolt ampere reactive (MVAR) supplied to MWe supplied, additional reactive power capability would be required. The licensee further stated that required reactive power of approximately 216 MVAR will be generated through the use of capacitor banks that will be distributed appropriately at designated load centers throughout the system, utilizing the existing generator-exciter control system and governed by operational procedures. The licensee provided a regulatory commitment to install these capacitor banks. Also, in Reference 16, the licensee confirmed that the capacitor banks will be installed and connected to the system prior to EPU implementation.

The transient stability analysis of the grid stability study was performed in order to examine the transient behavior of the impact of the proposed uprate on the Entergy power system. The NRC staff reviewed the results of the study and concludes that the system remained stable after all simulated faults. The critical clearing time analysis, which is part of the grid stability study, was performed for faults on lines and transformers in the GGNS 500 kV substations. The NRC staff reviewed the results of the analysis and concludes that the power uprate does not adversely impact the critical clearing at either GGNS 500 kV substations and that no voltage criteria violation occurred after the normal cleared three-phase fault.

The NRC staff has reviewed the grid stability analysis included in Attachment 12 of the EPU LAR. The NRC staff concludes that the analysis was performed at a value higher than the expected EPU load and that it showed that after the installation of the capacitor banks, there will be no adverse effect on the electric power grid from the proposed power uprate.

2.3.2.2 Main Generator

According to the EPU LAR, the main generator will be rewound to enhance reliability under EPU conditions. The new megavolt ampere (MVA) rating will be 1,600 MVA (revised from existing 1,525 MVA) at a power factor of 0.9. In Reference 16, the licensee stated that the maximum expected gross output is 1523.5 MWe (1600 MVA at 0.952 power factor). The NRC staff has reviewed the ratings of the modified generator and confirmed that they are at the maximum expected gross output for GGNS at the proposed EPU conditions. Therefore, the NRC staff concludes that the generator will support the proposed EPU conditions.

2.3.2.3 Isolated Phase Bus(es)

In Attachment 5B of the EPU LAR the licensee stated that the isolated phase bus (IPB) duct cooling system is being modified to increase the IPB duct continuous current rating to provide additional margin for operation at EPU output and reduced voltage. At CLTP, the IPB has a duty of 42,128 Amps while at EPU load it has a duty of 44,200 Amps. In Reference 16, the licensee provided additional details on this modification. The licensee stated that due to an evaluation from an IPB duct manufacturer the following modifications will be implemented: upgrade of the delta buses, installing a higher capacity IPB cooler, change the IPB cooling air flow path, increase cooling water flow to the IPB and increase cooling fan airflow. The NRC staff has reviewed the information provided in Reference 16, and determined that the IPB duct manufacturer's evaluations showed that the IPB will be capable of performing its intended function at EPU conditions following the planned modifications and that the IPB rating will support the maximum output of GGNS at the EPU conditions. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the IPB system.

2.3.2.4 Main Transformer(s)

According to the licensee the main step-up transformer at CLTP is loaded at 1,525 MVA and at EPU duty it will need to be loaded at 1,600 MVA. The licensee stated that the main step-up transformer is rated at a maximum 1,530 MVA and it will be replaced prior to operation at EPU conditions in order to increase transformer power handling capacity. The new main step up transformer will be rated at 1,650 MVA. The NRC staff has reviewed the EPU LAR and concludes that the replacement main step-up transformer will be rated higher than the expected EPU electrical power output; and therefore it will not adversely affect safe operation under EPU conditions.

2.3.2.5 Protective Relay Settings

The licensee has performed a review of protective relaying for the main generator, main step-up transformer and switchyard. For the switchyard, the licensee concluded that the existing protective relay setpoints do not need to be changed for the EPU conditions, while the main generator and main step-up transformer protective relay setpoints require supplementary calculation. In Reference 16, the licensee provided additional discussion on the revised calculations performed for the main generator and main step-up transformer setpoints. After further evaluation and examination of the Main Generator Differential, Negative Phase Sequence, Phase Distance, Power Directional, Loss of Field, Main Transformer Differential, and the Unit Differential protection relays, the licensee concluded that the setpoints for these relays are adequate for EPU conditions and do not need to be changed. The NRC staff has reviewed the summary of the process performed for the calculation of the protective relay setpoints for the switchyard, the main generator and main step-up transformer, and concludes that the results of these calculations demonstrate that the protective relaying setpoints remain adequate at EPU levels. After analyzing the steady state load flow, static and dynamic motor start and short circuit calculations using Electrical Transient Analyzer Program (ETAP) to evaluate the performance of the GGNS auxiliary electric power distribution system under EPU conditions, the licensee determined that no change is required to the degraded voltage setpoints as a result of the EPU. The NRC staff has reviewed the summary of the degraded voltage calculations and the results of these calculations, and concludes that they demonstrate that the degraded voltage setpoints remain adequate at EPU levels.

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 the offsite power system will continue to meet the requirements of GDC 17 following implementation of the proposed EPU. The offsite power system has capacity and capability to supply power to all safety loads and other required equipment. The NRC staff further concludes that the proposed EPU will not adversely affect grid reliability or stability. Based on the above, the NRC staff concludes that the proposed EPU is acceptable with respect to the offsite power system.

2.3.3 AC Onsite Power System

Regulatory Evaluation

The ac onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems 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, "Electric power systems," insofar as it requires the system to have the capacity and capability to perform its intended functions during AOOs and accident conditions. Specific review criteria are contained in SRP Sections 8.1, "Electric Power – Introduction," and 8.3.1, "AC Power Systems (Onsite)" (Reference 62).

Technical Evaluation

The ac power is provided from the transmission system, 500 kV switchyard, and from onsite diesel generators. The ac onsite power system consists of the 34.5 kV switchgear, 13.8 kV switchgear, 6.9 kV switchgear, 4.16 kV switchgear, 480 V load and motor control centers, 208Y/120V distribution panels, uninterruptible power supply systems, and diesel generators. The licensee reviewed the ac system under both normal and emergency operating scenarios using the electrical analysis software ETAP. The software was used to compute loads and calculate voltage drop and short circuit current values under the scenario of the additional electric load that would result from the proposed EPU. In Reference 16, the licensee confirmed that it used the nuclear version of the ETAP software and noted its certifications and qualifications.

In Reference 16, the licensee stated that the existing emergency diesel generator (EDG) loads, load sequencing and equipment loading times remain bounding at EPU conditions. The NRC staff reviewed the licensee's response and concludes that due to no changes in the EDG loads and load sequencing, there will not be any need for changes to the fuel oil requirements.

In the PUSAR Table 2.3-3, Electrical Equipment Ratings and Margins, the licensee indicated that the Engineered Safety Feature (ESF) Service Transformers 11 and 21 have an increased loading from 40.54 and 43.54 MVA to 42.64 and 44.15 MVA, respectively, as a result of the EPU. The NRC staff confirmed that the increased loading will remain within each transformer rating (90 MVA), with adequate margin. Based on this evaluation, the NRC staff concludes that the current emergency power system remains adequate and has sufficient capacity to support all required loads for safe shutdown, to maintain a safe shutdown condition, and to operate the ESF equipment following postulated accidents.

In the PUSAR Table 2.3-4, the licensee indicated that the loading of the condensate booster pump will increase from 1,927 horsepower (hp) at CLTP to 2,111 hp under EPU conditions. The loading of the condensate pump will increase from 1,316 hp at CLTP to 1,403 hp under EPU conditions. The loading of the reactor recirculation pump will increase from 7,511 hp at CLTP to 7,554 hp under EPU conditions. The NRC staff has verified that the increased loadings on the condensate booster pump, the condensate pump and the reactor recirculation pump remain within their nameplate ratings of 2,500 hp, 1,750 hp, and 7,940 hp, respectively. The feeder cables to these motors are adequate for the EPU conditions. Also, in the EPU LAR Section 2.3.3.2, the licensee stated that the existing protective relaying settings for the condensate booster pump, condensate pump, and reactor recirculation pump were based on these nameplate ratings and, therefore, remain unchanged. Therefore, the NRC staff determined that the protective relay settings remain adequate after accommodating the increased load on the non-safety 34.5 kV, 6.9 kV, and 4.16 kV systems. In Reference 16, the licensee clarified that the protection coordination will be maintained between the pump motor breakers and the 34.5 kV, 6.9 kV, and 4.16 kV switchgear main feeder breakers under EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ac onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the ac onsite power system will continue to meet the requirements of GDC 17 following implementation of the proposed EPU. The onsite power system has capacity and capability to supply power to all safety loads and other required equipment. Based on the above, the NRC staff concludes that the proposed EPU is acceptable with respect to the ac onsite power system.

2.3.4 DC Onsite Power System

Regulatory Evaluation

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 are based on GDC 17, "Electric power systems," insofar as it requires the system to have the capacity and capability to perform its intended functions during AOOs and accident conditions. Specific review criteria are contained in SRP Sections 8.1, "Electric Power – Introduction," and 8.3.2, "DC Power Systems (Onsite)" (Reference 62).

Technical Evaluation

The dc power system is composed of station batteries, battery chargers, and dc distribution system and it provides dc power to protective relaying, control, instrumentation and other dc loads. The system is made up of a non-safety-related portion and a safety-related portion that is required to safely shutdown the reactor in case of a DBA.

In Section 2.3.4 of Attachment 5B of the EPU LAR, the licensee stated that there are no changes to the loads of the safety-related 125 Vdc batteries. The NRC staff confirmed that 125 Vdc division I, II and III batteries remain unchanged by the EPU. According to the licensee, the 125 Vdc non-safety-related batteries will have a small change in the dc load due to modifications to the Radial Wells. The NRC staff confirmed that the battery margin for the 125 Vdc non-safety-related batteries 1G3 and 2G3 will decrease from 4.2 percent at CLTP to 1.3 percent under EPU conditions. Also, the NRC staff verified that the 250 Vdc non-safety-related battery loads will not be affected by the EPU. Therefore, the NRC staff concludes the dc on-site power system is not adversely impacted by 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 the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the dc onsite power system will continue to meet the requirements of GDC 17 following implementation of the proposed EPU. The system has the capacity and capability to supply power to all safety loads and other required equipment. Based on the above, the NRC staff concludes that the proposed EPU is acceptable with respect to the dc onsite power system.

2.3.5 Station Blackout

Regulatory Evaluation

Station blackout (SBO) refers to a complete loss of ac electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the LOOP concurrent with a turbine trip and failure of the onsite emergency ac power system. SBO does not include the loss of available ac power to buses fed by station batteries through inverters or the loss of power from alternate ac sources. The NRC staff's review focused on the impact of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC's acceptance criteria for SBO are based on 10 CFR 50.63, "Loss of all alternating current power." Specific review criteria are contained in SRP Section 8.1, "Electric Power – Introduction," and Appendix 8-A to SRP Section 8.2, "Offsite Power System" (Reference 62); and other guidance provided in Matrix 3 of RS-001 (Reference 54).

Technical Evaluation

The licensee re-evaluated SBO using the guidelines of the Nuclear Management and Resources Council, Inc. (NUMARC) 87-00, "Guidelines and Technical Bases for NUMARC

Initiatives Addressing Station Blackout at Light Water Reactors," Revision 1, August 1991 (Reference 118), and NRC Regulatory Guide (RG) 1.155, "Station Blackout," August 1988 (Reference 119). The licensee stated that GGNS is able to show satisfactory response to an SBO event by satisfying the criteria used in assessing the characteristics of: condensate inventory for decay heat removal (DHR), Class 1E battery capacity, compressed air capacity, effects of loss of ventilation, and containment isolation.

The condensate inventory for DHR analysis was performed by the licensee and it showed a need for an additional approximately 24.4 percent volume, over that currently required for operation at CLTP (109,311 gallons), to ensure that adequate water volume is available to remove decay heat, depressurize the reactor, and maintain reactor vessel level above the top of active fuel. The NRC staff verified that this increase to approximately 136,014 gallons is within the current condensate storage tank reserve of 143,000 gallons.

In Reference 16, the licensee provided further details on Class 1E battery capacity. Based on the NRC staff's review, the licensee's calculations show that there is sufficient battery capacity in the Class 1E battery system to support DHR for the required coping duration of 4 hours.

The licensee stated that it has performed an evaluation to determine if air operated valves required for DHR have sufficient reserve air or can be manually operated under SBO conditions for the required coping duration of 4 hours. In Reference 16, the licensee showed that the SRVs at the higher EPU value of 86 manual pressure reduction cycles is below the design limit of 200 cycles. Therefore, the NRC staff concludes that GGNS has adequate compressed air capacity for an SBO event under EPU conditions.

For evaluating the effects of loss of ventilation, the areas that the licensee evaluated due to containing equipment necessary to cope with an SBO event are: drywell, steam tunnel, reactor core isolation cooling pump room, control room and upper cable spreading room and switchgear room/ inverter room. In Reference 16, the licensee provided a summary of the evaluation performed for each area and a discussion on the selection of dominant areas of concern for the SBO analysis. The NRC staff reviewed this summary and concludes that the evaluations performed by the licensee demonstrate that the equipment operability is maintained because the SBO environment is milder than the existing design and qualification bases. Furthermore, the NRC staff concludes that the containment isolation capability is not adversely impacted by the SBO event under EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the plant's ability to cope with and recover from an SBO event for the period of 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. Based on the above, the NRC staff concludes that the proposed EPU is acceptable with respect to SBO.

2.4 Instrumentation and Controls

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

Regulatory Evaluation

Instrumentation and control (I&C) systems are provided (1) to control plant processes that have a significant impact on plant safety, (2) to initiate the reactivity control system (including control rods), (3) to initiate the engineered safety features (ESFs) and essential auxiliary supporting systems, and (4) for use to achieve and maintain the plant in a safe-shutdown condition. Diverse I&C systems and equipment are provided for the express purpose of protecting against potential common-mode failures of I&C protection systems. The NRC staff reviewed the reactor trip system, the engineered safety feature actuation system (ESFAS), safe-shutdown systems, control systems, and diverse I&C systems for the proposed EPU to ensure that the systems and any changes necessary for the proposed EPU are adequately designed so that the systems continue to meet their safety functions. The NRC staff also conducted its review to ensure that system failures do not affect safety functions. The NRC's acceptance criteria related to the design quality of protection and control systems are based on paragraphs (a)(1) and (h) of 10 CFR 50.55a, "Codes and standards," and GDC 1, "Quality standards and records," GDC 5, "Sharing of structures, systems, and components," GDC 11, "Reactor inherent protection," GDC 12, "Suppression of reactor power oscillations," GDC 13, "Instrumentation and control," GDC 14, "Reactor coolant pressure boundary," GDC 15, "Reactor coolant system design," GDC 19, "Control room," GDC 20, "Protection system functions," GDC 22, "Protection system independence," GDC 23, "Protection system failure modes," GDC 25, "Protection system requirements for reactivity control malfunctions," GDC 26, "Reactivity control system redundancy and capability," GDC 40, "Testing of containment heat removal system," and GDC 42, "Inspection of containment atmosphere cleanup systems." Specific review criteria appear in SRP Sections 7.0, "Instrumentation and Controls – Overview of Review Process," 7.2, "Reactor Trip System," 7.3, "Engineered Safety Features Systems," 7.4, "Safe Shutdown Systems," 7.7, "Control Systems," and 7.8, "Diverse Instrumentation and Control Systems" (Reference 62).

Technical Evaluation

Entergy referenced NEDC-33004P, Revision 4, "Constant Pressure Power Uprate," July 2003 (CLTR) (Reference 55). The constant pressure power uprate (CPPU) approach maintains a plant's current maximum operating reactor pressure. The constant pressure constraint, along with other required limitations and restrictions discussed in the CLTR, allows a simplified approach to power uprate analyses and evaluations.

Entergy stated that its setpoint calculations in support of the EPU LAR were based on NEDC-31336P-A, "General Electric Instrument Setpoint Methodology," September 1996 (Reference 120), which includes the NRC-approved SE dated November 6, 1995.

The EPU LAR is based upon use of the Nuclear Management and Control (NUMAC) Power Range Neutron Monitoring System (PRNMS) to replace the existing analog APRM subsystem of the existing Neutron Monitoring System which was approved by NRC in Amendment No. 188 dated March 28, 2012 (Reference 121).

2.4.1.1 Suitability of Existing Instruments and Settings

For the proposed power uprate, the licensee evaluated the existing instruments of the affected nuclear steam supply systems and BOP systems to determine their suitability for the revised operating range of the affected process parameters.

Where operation at the power uprate condition affected safety analysis limits, the licensee verified that the acceptable safety margin continued to exist under all power uprate conditions. The following instruments and settings shown below in Table 2.4-1 were not affected because they are expressed in terms of percent rated thermal power (% RTP), and thus they were re-scaled or adjusted for EPU.

Table 2.4-1. Instruments and Settings Not Affected by the EPU

Instrument/Parameter	Description
Reactor Protection System (RPS) – Allowable value for neutron flux – high, setdown	The current allowable value (AV) is ≤20% RTP. The EPU does not modify this value. No specific safety analyses take credit for this function, which indirectly ensures reactor power does not exceed 21.8% RTP before the Mode Switch is placed in "RUN."
Control rod block instrumentation channel	The surveillance requirements (SR) identified in Technical Specification (TS) 3.3.2.1 are being conservatively maintained at the same percent RTP as CLTP. Thus, the % RTP is unchanged in terms of % RTP for EPU. Maintaining this value provides a reasonable time for testing to be completed and does not affect the operation or operability of the control rod block instrumentation.
Allowable value of the low power setpoint (LPSP) trip units	The AV shall be greater than or equal to 10% RTP and less than or equal to 35% RTP. The current values are lower than these values, and thus protect the EPU analytical limit. Maintaining these values at the same percent RTP as CLTP is conservative (because the analytical limit for this trip is 8% RTP, so an AV of 10% RTP continues to protect the EPU analytical limit).
Analytical limit to bypass RWL [rod withdrawal limiter] high power function	The stated % RTP, which is an analytical limit, is unchanged as a result of EPU.
Rod Withdrawal Limiter (RWL) function	The RWL function shall be operable when thermal power is greater than 35% RTP. The EPU A analytical limit for this value is 36% RTP. The current AV (35%) is conservative and continues to protect the EPU analytical limit.
Rod Pattern Controller (RPC) function	The RPC function shall be operable when thermal power is less than or equal to 10% RTP. The EPU analytical limit for this value is 8% RTP. Maintaining the stated % RTP, which is the AV, at the current CLTP value is conservative and continues to protect the EPU analytical limit.

Where necessary, the licensee revised the setpoint and uncertainty calculations for the affected instruments. Apart from a few devices that were changed (as described below), the licensee's evaluations found most existing instrumentation acceptable for proposed power uprate operation. The licensee's evaluation resulted in the changes at GGNS outlined below.

Table 2.4-2. Instruments and Settings Affected by the EPU

Instrument/Parameter	EPU Impact/Change
Average power range monitors (APRMs)	Will affect the performance of the PRNMS. In response to NRC staff's RAI dated January 26, 2011 (Reference 122), the licensee stated in Reference 7 that the EPU modification is generically dispositioned by the CPPU CLTR. Will be calibrated to read 100% at EPU RTP level.
Local power range monitors (LPRMs)	Will decrease the neutronic life of the LPRM detectors and increase the radiation levels of the traversing in-core probes (TIPs). LPRMs are designed as replaceable components. The LPRM accuracy at the increased flux is within specified limits, and LPRM lifetime is an operational consideration that is handled by routine replacement. The LPRMs and TIPs installed at GGNS are in accordance with the requirements established by the GEH design specifications. Generically dispositioned by the CPPU CLTR.
Intermediate range monitors	Will be adjusted, in accordance with normal plant procedures, to ensure that overlap with APRMs and intermediate range monitors is adequate. Generically dispositioned by the CPPU CLTR.
Source range monitors	Will be adjusted, in accordance with normal plant procedures, to ensure that overlap with Intermediate range and source range monitors is adequate. Generically dispositioned by the CPPU CLTR.
Rod control and information system (RCIS)	Will rescale the RCIS Rod Pattern Controller LPSP (lower bound) to retain the CLTP analytical limit value in terms of absolute reactor power (MWt). This resulted in a lower RTP of 8% that adds flexibility and is consistent with current operations. Based on this, the current conservative setpoint of 100 psig Turbine First Stage Pressure (TFSP) for RPC LPSP (lower bound) is being retained.
Main steam line high flow	Will change setpoint in terms of absolute steam flow to maintain the analytical limit at 140% of rated steam flow. This calculation and associated TS change is discussed later in this evaluation.

In addition, several BOP monitoring and control instruments will be recalibrated and rescaled to accommodate for the EPU. The pressure control system, turbine bypass system, feedwater control system and leak detection system are all non-safety-related and all are generically dispositioned by the CPPU CLTR.

Based upon the data provided by the licensee, the NRC staff concludes that the instruments identified above – with the noted modifications – are capable of serving their intended functions at EPU conditions. The licensee will make these noted modifications to accommodate the revised process parameters affected by the EPU. Discussion of instrumentation and parameter changes that modify the setpoint or values of TSs for GGNS is provided in Section 3.3 of this SE.

2.4.1.2 Suitability of New Instruments

For the proposed power uprate, the licensee will replace the following nuclear steam supply systems and BOP systems. These instruments/parameters were evaluated to determine their suitability for the operating range of the process parameters, and that acceptable safety margin continued to exist under all power uprate conditions.

Suitability of the PRNMS and approval of Option III operation was submitted for evaluation by a separate LAR dated November 3, 2009 (Reference 123). The PRNMS LAR was approved by Amendment No. 188 dated March 28, 2012 (Reference 121). The PRNMS design includes an Oscillation Power Range Monitor (OPRM) capability, which implements a GEH version of the Boiling Water Reactor Owners' Group (BWROG) Option III detect-and-suppress long-term reactor core stability solution. This OPRM upscale function provides the capability to detect and suppress reactor thermal-hydraulic instabilities.

In support of the power uprate, Entergy made modifications to the high-pressure (HP) turbine, which affected functions in the turbine first-stage pressure, RCIS rod pattern controller, and RCIS rod withdrawal limiter.

Table 2.4-3. Instruments/Parameters Affected by the EPU

Instrument/Parameter	EPU Impact/Change
PRNMS	A license condition was proposed to ensure NRC approval of the PRNMS LAR dated November 3, 2009 (Reference 123), is obtained prior to increasing power above 3,898 MWt (CLTP). This license condition was met with the issuance of Amendment No. 188 (Reference 121). In Reference 7, GGNS stated that it evaluated this system with respect to CLTR requirements (NEDC-33004P-A) and found that it met the GEH design specifications. The EPU will affect APRM flow-biased simulated thermal power (STP) scrams and rod block and APRM neutron flux setdown scram and rod block functions. These are evaluated later in this section.

Instrument/Parameter	EPU Impact/Change
OPRM Upscale Applicable Mode	The PRNMS LAR identified a value of 24% RTP for this TS. This function was introduced in the PRNMS LAR dated November 3, 2009 (Reference 123). The PRNMS LTR NEDC-32410P-A established this function to be ≥ 24%. The EPU will change OPRM Upscale from the existing value of 24% RTP to 21%. The change supports the GEH methodology requirement, described in the PRNMS LAR, for the value to be 5% less than the OPRM trip enabled region boundary, which is evaluated later in this section.
HP Turbine	Will affect turbine first stage pressure (TFSP) scram bypass permissive, RCIS Rod Pattern Controller (RPC) Low Power Setpoint, and RCIS RPC High Power Setpoint. Will also recalibrate or replace turbine first-stage pressure instruments and verify/validate relationship between instruments and RTP during startup testing following replacement of the high-pressure turbine.

Based upon the data provided by the licensee, the NRC staff concludes that the instruments/parameters changes identified above are appropriate for operation at EPU conditions. As noted above, this evaluation does not constitute approval of the PRNMS LAR, which was approved by Amendment No. 188 issued on March 28, 2012 (Reference 121).

2.4.1.3 Instrument Setpoint Methodology

To ensure that adequate operational flexibility and necessary safety functions are maintained at the EPU RTP level, Entergy will modify several instrument setpoints. For those instruments that will not be changed for the EPU, GGNS followed the simplified process outlined in the CLTR to determine instrument setpoint. Where the power increase results in new instruments being employed, a setpoint calculation was performed and TS and/or Technical Requirements Manual (TRM) changes are implemented, as appropriate. In this case, Entergy used the GE Nuclear Energy, "General Electric Instrument Setpoint Methodology," NEDC-31336P (Reference 120), to determine the new setpoint value.

For the EPU, GGNS will replace the analog APRM with the NUMAC PRNMS. This replacement resulted in a number of TS and setpoint revisions associated with the APRM monitors that affect the values calculated for the EPU. Due to the inclusion of the new PRNMS system in the bases for operation at the requested EPU conditions, this evaluation considered values consistent with the implementation of the new PRNMS.

In support of this evaluation, the NRC staff met with representatives from Entergy and GEH on May 24, 2011, to review the setpoint calculations that impacted the GGNS TSs. The calculations reviewed were the Main Steam Line (MSL) Flow – High, APRM Fixed Neutron Flux – High, and the APRM Flow-Biased Simulated Thermal Power – High. The summary of the setpoint audit is contained in an audit report dated August 10, 2011 (Reference 124).

The following subsections described the setpoint values for instruments that were changed for the EPU.

2.4.1.3.1 Main Steam Line (MSL) — High Flow Isolation

The main steam line (MSL) – high flow isolation setpoint is used to initiate the isolation of the Group 1 primary containment isolation valves. This actuation is credited in the UFSAR accident analysis. The EPU modification will increase reactor power level and steam flow, and thus will have an effect on the MSL - High Flow Isolation. The existing instrumentation can accommodate the new setpoint and the current analytical limit and allowable value (AV) (in terms of percent of rated steam flow) will be maintained. However, the absolute values of these limits and setpoint (in terms of pounds per square inch differential (psid)) will change. The current setpoint is 169.0 psid and is being revised to 254.7 psid for EPU based upon maintaining the analytical limit at 140 percent of rated steam flow. Attachment 5B, Section 2.4.2, of the EPU LAR summarizes the setpoint calculation for this parameter.

The NRC staff reviewed the values presented in Section 2.4.2, Attachment 5B, as well as reviewed this calculation and associated spreadsheet during an audit on May 24, 2011; see NRC audit report dated August 10, 2011 (Reference 124). For operations at the proposed EPU power level, the steam flow would be increased and the setpoint used to protect the analytical limit of 140 percent will correspondingly increase. The single-sided setpoint methodology described in NEDC-31336P is used in the performance of this calculation.

For the calculation performed, the process measurement accuracy is considered a systematic accuracy (i.e., bias); therefore, it was not combined with other terms as a root-sum of the squares, but was considered to be a bias term and appropriately added. The error terms for the Rosemount transmitter had all been normalized to 2σ uncertainty estimates (using information supplied by Rosemount). Two different model Rosemount transmitters are used at GGNS, and although the data for the two models was very similar (if not largely identical), where any differences existed, the setpoint calculation for the MSL high flow used the more conservative data. Bias terms were appropriately identified in the calculation – including spreadsheet input values and the spreadsheet algorithms. Non-bias uncertainties were appropriately incorporated and combined. Surveillance intervals were identified to form a basis for drift values used. A GE proprietary technique was used to generate drift data that was not specifically supplied by a vendor. Any impact to signal uncertainty from environmental conditions that the instrumentation was expected to experience was identified and incorporated into the calculation. Rounding of the NTSP values was in the direction away from the analytical limit (to ensure a conservative value). In the MSL high flow calculation, the NTSP selected was more conservative than what would nominally be required to meet NRC requirements and guidance. This extra conservatism was adopted to minimize generation of licensee event reports (LERs).

Based on the above, the NRC staff concludes that the uncertainties terms and setpoint calculation are acceptable to meet 10 CFR 50.36(c)(1), "Safety limits, limiting safety system settings, and limiting control settings."

2.4.1.3.2 APRM Fixed Neutron Flux – High Scram

The APRM Fixed Neutron Flux - High scram function protects against fast reactivity transients. The current AV setpoint is 120 percent and is being revised to 119.3 percent. By letter dated July 28, 2011 (Reference 23), the licensee documented its evaluation of the change based on the GE Instrument Setpoint Methodology. The NRC staff reviewed the GEH methodology and the values presented in this document and concluded that Entergy provided appropriate consideration of expected uncertainties and demonstrates that the operating setpoint may be set to 119.3 percent at EPU conditions. Based on the information provided, the NRC staff concludes that the uncertainties values and setpoint methodology are acceptable.

The NRC staff reviewed input data for these calculations as well as the spreadsheet used to perform the computations during an audit on May 24, 2011 (Reference 124). Both spreadsheet algorithms and values were available and were reviewed. The APRM Fixed Neutron Flux – High values for AV and NTSP are driven by the analytical limit, which remains at 122 percent. The single-sided setpoint methodology described in NEDC-31336P is used in the performance of this calculation.

The uncertainty values for LPRM detectors included bias to account for loss of instrument sensitivity between seven day surveillance intervals. In the calculation summary provided in the licensee's letter dated February 23, 2011 (Reference 7), several of the summary tables contained ambiguous wording in the "comments" attached to certain calculated values. Since that time, GE has modified comments 6 and 20 (to clarify their intended meaning) and the amended version was submitted as an attachment to the letter dated July 28, 2011 (Reference 23). The NUMAC PRNMS's accuracies are provided for both the flow electronics and the power electronics. The calculation provided presents the values for these two components (in Tables 2.2 and 2.3 of the PUSAR (Reference 57)). The neutron flux scram analytical limit is not proposed to change from the CLTP analytical limit; however, the AV and NTSP have changed (to be more conservative in terms of %RTP) for the EPU.

Bias terms were appropriately identified in the calculation – including spreadsheet input values and the algorithms. Non-bias uncertainties were appropriately incorporated and combined. Surveillance intervals were identified to form a basis for drift values used. [Note: In preparation for a future licensing submittal, GGNS did use 24 months as a (currently) conservative assumption for its interval between refueling to determine drift for setpoint calculations. This is conservative because it adds additional margin between the setpoint and analytical limit.] A GE proprietary technique was used to generate drift data that was not specifically identified by a vendor. Any impact to signal uncertainty from environmental conditions that the instrumentation was expected to experience was identified and incorporated into the calculation. Rounding of the NTSP values was in the direction away from the analytical limit (to ensure a conservative value). The NRC staff noted that although the spreadsheet and calculation summary documents showed that the temperature effect and humidity effect errors for the NUMAC equipment were "included within the NUMAC accuracy performance specification" upon review of a copy of a design calculation for the NUMAC performance, and its reference specifications, it was noted that a calculation had been performed to demonstrate the negligible magnitude of the temperature effect specification, but no calculation had been performed for the humidity effect specification. Yet, the calculation summary merely stated that the humidity effect was enveloped without providing a calculation to demonstrate that it was, just as it had for the temperature effect. The NRC staff noted that this appeared to be an unverified assumption, which would need further amplification or a statement as to why it is considered negligible. In Reference 23, the licensee provided the performance specification temperature and humidity limits for the system and showed that it was in range of the expected control room environment, in which the equipment would be located. The response further stated that qualification testing had confirmed acceptable error performance relative to humidity variation over the expected range of the operational environment. Additional information regarding the humidity tests was submitted by the licensee in its letter dated May 31, 2011 (Reference 125), to support the PRNMS LAR review and was reviewed by the NRC staff for this amendment.

By letter dated June 3, 2010 (Reference 126), in response to an NRC staff RAI related to the PRNMS LAR dated May 4, 2010 (Reference 127), the licensee stated that it "will set the as-found tolerance equal to the Square Root Sum of the Squares (SRSS) combination of as-left tolerance and the projected drift. The as-found and as-left tolerances will be reflected in the associated surveillance test procedures. GGNS committed to complete this "Prior to startup from the 2012 refueling outage." The NRC staff provided a supplemental RAI dated June 29, 2011 (Reference 128), regarding the refueling outage length assumed in the as-found calculations, since Entergy is planning to move from an 18- to 24-month refueling outage. Pursuant to its RAI response dated July 28, 2011 (Reference 23), the licensee clarified that as-found tolerances related to the PRNMS would use a 24-month assumption for length between channel calibrations. The PRNMS LAR has proposed the 24-month calibration interval such that the as-found tolerance would not be dependent on time between refueling outages. The RAI response further explained that for all other EPU affected instrumentation, the as-found tolerance calculations will continue to use the assumption of an 18-month refueling cycle.

Based on the above, the NRC staff concludes that the uncertainties terms and setpoint calculation are acceptable to meet 10 CFR 50.36(c)(1), "Safety limits, limiting safety system settings, and limiting control settings."

2.4.1.3.3 APRM Flow Biased Scram

This function is referred to in the GGNS TSs as the APRM Flow Biased Simulated Thermal Power (STP) - High. The APRM Flow Biased STP scram setpoint function is designed to protect against slow reactivity transients. The licensee notes in its LAR that this setpoint is not directly tied to a limiting safety system setting. The AV is being revised in accordance with the CLTR (NEDC-33004P). The licensee's RAI response dated July 28, 2011 (Reference 23), documents its evaluation of the change based on the GE Instrument Setpoint Methodology. The new setpoints are proposed to be:

Two-Loop Operation: 0.58W + 59.1% RTP and ≤ 113% RTP
Single-Loop Operation: 0.58W + 37.4% RTP

"W" is the total recirculation drive flow in percent of rated flow. This change rescales the allowable value based on the proposed changes in power level for EPU conditions.

The NRC staff reviewed input data for these calculations as well as the spreadsheet used to perform the computations (Reference 124). Both spreadsheet algorithms and values were available and were reviewed. The single-sided setpoint methodology described in NEDC-31336P is used in the performance of this calculation.

The uncertainty values for LPRM detectors included bias to account for loss of instrument sensitivity between 7-day surveillance intervals. The NUMAC PRNMS's accuracies are provided for both the flow electronics and the power electronics. Bias terms were appropriately identified in the calculation – including spreadsheet input values and the algorithms. Non-bias uncertainties were appropriately incorporated and combined. Surveillance intervals were identified to form a basis for drift values used. A GE proprietary technique was used to generate drift data that was not specifically identified by a vendor. Any impact to signal uncertainty from environmental conditions that the instrumentation was expected to experience was identified and incorporated into the calculation. Rounding of the NTSP values was in the direction away from the AV (to ensure a conservative value). To determine the APRM flow biased scram, GE determined the slope and coordinate (or interception), which is done using the errors and accuracy of the loop components. These functions use a single-loop operation (SLO) setting adjustment to calculate the single loop NTSP from the two-loop operation (TLO) NTSP value. Note that the SLO setting adjustment only applies to NTSP because it is only related to the instrument settings.

These values are based on the GGNS PRNMS LAR (Reference 123). In Reference 126, the licensee stated that it will set the as-found tolerance equal to the SRSS combination of as-left tolerance and the projected drift. The as-found and as-left tolerances will be reflected in the associated surveillance test procedures. Entergy committed to complete this "Prior to startup from the 2012 refueling outage."

Based on the above, the NRC staff concludes that the uncertainties terms and setpoint calculation are acceptable to meet 10 CFR 50.36(c)(1), "Safety limits, limiting safety system settings, and limiting control settings."

2.4.1.3.4 APRM Setdown Scram in Startup Mode

The APRM setdown scram setpoint function provides a redundant scram (in addition to the Intermediate Range Monitor) for reactivity transients in the startup mode. In Table 1.6 of Reference 23, the licensee documented its evaluation of the change. The licensee explained that this function does not provide a safety function for operations as described in the EPU LAR; therefore, this function does not provide a safety function for post-EPU operation and an analytical limit is not required.

The NRC staff reviewed the information presented in the RAI responses (References 7 and 23) and concludes that because the EPU value does not exceed the 25 %RTP CLTP, the EPU does not modify the AV and continues to provide the TS safety margin. Thus, this value remains the same in terms of percent rated power. However, a new NTSP was calculated based upon use of the new PRNMS. The NTSP for this function was calculated based on the AV. The current NTSP is 15% RTP and is being revised to 18% RTP. Based on the above, the NRC staff concludes that the uncertainties values and setpoint methodology are acceptable.

2.4.1.3.5 APRM Setdown Rod Block

The APRM setdown rod block setpoint function provides a redundant rod block (in addition to the Intermediate Range Monitor) for reactivity transients in the startup mode. In Table 1.7 of Reference 23, the licensee documented its evaluation of the change. The licensee explained that this function does not provide a safety function for operations as described in the EPU LAR; therefore, this function will not provide a safety function for post-EPU and an analytical limit is not required.

The NRC staff reviewed the information presented in the RAI responses (References 7 and 23) and concludes that the EPU will not modify the AV and NTSP for this function. These values are necessary to ensure that a rod block occurs prior to the setdown function reaching conditions for a scram. Based on the above, the NRC staff concludes that retaining this value is acceptable as it still protects the new APRM setdown scram.

2.4.1.3.6 APRM Downscale Rod Block

The APRM downscale rod block setpoint function provides indication of instrument failure or insensitivity and assures proper overlap between the neutron monitoring systems. The licensee's RAI response in Reference 23 documents the licensee's evaluation of the change based on the GE Instrument Setpoint Methodology. The EPU will not modify the AV for this function. However, a new NTSP was calculated. The current NTSP is 4% RTP and is being revised to 5% RTP. [Note: this setpoint is approached from above these values, so changing from 4-5% RTP will enact the rod block sooner and, thus, is a change in a conservative direction.]

Based on the above, the NRC staff concludes that the change to the setpoint is acceptable to meet 10 CFR 50.36(c)(1), "Safety limits, limiting safety system settings, and limiting control settings."

2.4.1.3.7 OPRM Upscale Function

The OPRM is used to monitor regions of the reactor core for thermal-hydraulic instability. The OPRM trip-enabled region is generically defined as the region on the power/flow map with power greater than or equal to 30% RTP and core flow less than 60 percent of rated core flow. For EPU, the GGNS OPRM trip enabled region is rescaled to maintain the same absolute power/flow region boundaries. Because the rated core flow is not changed, the 60 percent core flow boundary is not rescaled. At the CLTP conditions, the OPRM is enabled at 29% of rated power and is confirmed operable at 24% of the rated power (Reference 129Attachment 4 of Reference 85). Further, Entergy explained that OPRM trip setpoints correspond to a pre-determined number of confirmed oscillations and pre-determined oscillation amplitude, and are not calculated by GEH setpoint methodology. Thus, these OPRM setpoints do not have ALs, AVs, and NTSPs with margins based on instrument error and GEH setpoint methodology. The OPRM setpoints are nominal setpoints, which are established using BWROG methodology, NEDO-32465, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications, Licensing Topical Report," August 1996 (Reference 130). These OPRM setpoints are established as nominal values based on cycle specific reload stability analysis and are included in the Core Operating Limits Report (COLR).

The PRNMS LAR identified the OPRM upscale function was scaled to 29 percent CLTP boundary. For the EPU, Entergy proposed rescaling the OPRM upscale function to the 26 percent EPU thermal power limit using the CLTP/EPU ratio. Because the OPRM system will incorporate a 5 percent calibration error on the OPRM setpoints to address the bypass voiding uncertainty at low-flow conditions, this function will be 5 percent less than the OPRM trip enabled region boundary. Thus, OPRM Upscale Applicable Mode is being changed from the existing value of 24% RTP to 21% RTP. This change updates the TS changes submitted as part of the PRNMS LAR to reflect EPU conditions. Because the OPRM upscale function is a permissive and not a trip setpoint, this function is not explicitly considered in the stability analysis.

Based on the above, the NRC staff concludes that the change to the setpoint is acceptable to meet 10 CFR 50.36(c)(1), "Safety limits, limiting safety system settings, and limiting control settings."

2.4.1.3.8 The Turbine First Stage Pressure Scram Bypass

The turbine first stage pressure (TFSP) scram bypass setpoint serves to reduce scrams and recirculation pump trips at low power level where the turbine bypass system is effective for turbine trips and generator load rejections. The current analytical limit is 40% RTP and is being revised to 35.4% RTP. This change will maintain the analytical limit for EPU at an equivalent absolute thermal power. Table 2.4-1 of Appendix 5B of the EPU LAR documents the licensee's change for the analytical limit. The licensee is specifically altering the TS from which the setpoint derives to allow the bypass to enact at an equivalent absolute MWt value. Because the HP turbine will be modified to support EPU RTP level, the AV (in psig) value will be established and maintained in plant-specific documents (e.g., Technical Requirements Manual) in accordance with 10 CFR 50.36, "Technical specifications." The licensee will confirm the relationship of TFSP to reactor power during startup testing and make any adjustments to this calculation at that point, if necessary.

The TFSP scram bypass is represented in TS Section 3.3.1.1, Turbine Stop Valve Closure, Trip Oil Pressure – Low (Function 9), and Section 3.3.4.1, Turbine Control valve Fast Closure, Trip Oil Pressure – Low (Function 10). The analytical limit for Turbine Stop Valve Closure, Trip Oil Pressure – Low is changed from ≥40% RTP to ≥35.4% RTP. The analytical limit for the Turbine Control valve Fast Closure, Trip Oil Pressure – Low is changed from ≥40% RTP to ≥35.4% RTP. These modifications are necessary to maintain the same absolute thermal power that was evaluated for CLTP. In an RAI response (Reference 7), Entergy explained that the TFSP values necessary for calibration are maintained in plant-specific documents (e.g., TRM). Based on the information provided in the EPU LAR and RAI response, the NRC staff concludes that this is acceptable. In addition, these re-scaling of TS values is further discussed in SE Section 3.2.1.

2.4.1.3.9 RCIS Rod Pattern Controller (RPC) Low Power

This function is used to bypass the rod pattern constraints established for the control rod drop accident at greater than a pre-established low power level. For the EPU, Entergy has rescaled the lower bound of this function to maintain the current analytical limit value in terms of absolute power. The trip setpoint for this function depends on the modification for the HP turbine. The relationship of %RTP to TFSP is derived based on turbine design data that correlates TFSP to %RTP. Table 2.4-1 of Appendix 5B of the EPU LAR documents the licensee's change for the analytical limit. The values presented in this document include appropriate consideration of expected uncertainties and demonstrates that the operating setpoint may be set to 8 percent at EPU conditions. The EPU value is lower than the CLTP analytical limit value of 9% RTP. Thus, the current value setpoint of 100 psig TFSP for RPC is maintained. Based on the information provided in the EPU LAR, the NRC staff concludes that this is acceptable.

2.4.1.3.10 RCIS Rod Withdrawal Limiter (RWL) High Power

This function is credited in the control Rod Withdrawal Error (RWE) analysis. The RCIS RWL signal comes from the TFSP. The trip setpoint for this function depends on the modification for the HP turbine. The relationship of %RTP to TFSP is derived based on turbine design data that correlates TFSP to %RTP. [[ ]]. The EPU will modify the analytical limit in psig. This value will be revised prior to EPU implementation. The value presented in the TS in terms of %RTP.

In Reference 7, in response to an NRC staff RAI, Entergy explained that the TFSP values necessary for calibration are maintained in plant-specific documents (e.g., TRM).

Based on the information provided in the EPU LAR, the NRC staff concludes that there is reasonable assurance that the plant will operate in accordance with the safety analysis and that the operability of the instrumentation is ensured.

2.4.1.4 TS Changes Related to the Power Uprate

The licensee proposed the following TS changes to the I&C-related systems:

(1) From EPU LAR, Attachment 1, Section 4.1.10, TS Section 3.3.1.1., Required Actions

a. Action E

The value (in %RTP) for this limiting condition for operation (LCO) action specifies the power level that the reactor is to be reduced to if specified conditions are not met. The licensee proposed to revise the value for the required action from 40 percent RTP to 35.4 percent RTP in order to maintain this value at an equivalent absolute value in terms of MWt, given the new EPU RTP. Rescaling the %RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP. Based on the above, the NRC staff concludes that this approach affords an equivalent level of protection to the CLB and is acceptable.

b. Action F

The value (in %RTP) for this LCO action specifies the power level that the reactor is to be reduced to if specified conditions are not met. The licensee proposed to revise the value for the required action from 25 percent RTP to 21.8 percent RTP. The revision to the percent RTP is based on the fuel thermal monitoring threshold. Specifically, for EPU, the fuel thermal margin monitoring threshold is scaled down to ensure that monitoring is initiated, as explained in Section 2.8.2.1.2 in the PUSAR. Based on the above, the NRC staff concludes that this approach affords an equivalent level of protection to the CLB and is acceptable.

c. Action K

The value (in %RTP) for this LCO action specifies the power level that the reactor is to be reduced to if specified conditions are not met. The licensee proposed to revise the value for the required action from 24 percent RTP to 21 percent RTP. The change supports the requirement for the value to be 5 percent less than the OPRM trip enabled region boundary. Additional detail on the derivation of this value is found in Section 3.3.7 of this SE. This change updates the TS changes submitted as part of the PRNMS LAR to reflect EPU conditions. Based on the information presented, the NRC staff concludes that the change to the TS is acceptable to meet 10 CFR 50.36(c)(1).

(2) From EPU LAR, Enclosure 5B, Section 4.1.10, TS Section 3.3.1.1, RPS Instrumentation, Surveillance Requirement (SR) 3.3.1.1.2

This SR instructs operators to verify the absolute difference between APRM readings and calculated power to be within specified tolerance. The %RTP values define the applicability of the SR (i.e., the SR must be performed when the reactor is at or above the specified RTP). The licensee proposed to revise the values in the SR from 25 percent RTP to 21.8 percent RTP. These values are nearly equivalent in terms of MWt (i.e., change from ~975 MWt to ~961 MWt). The revision to the percent RTP is based on the fuel thermal monitoring threshold, described in the PUSAR Section 2.8.2.1.2. Based on the above, the NRC staff concludes that this change is acceptable.

(3) From EPU LAR, Enclosure 5B, Section 4.1.10, TS Section 3.3.1.1, RPS Instrumentation, SR 3.3.1.1.14

This SR pertains to ensuring that certain turbine-related functions are not bypassed when operating above a specified power level. The licensee proposed to revise the value in the SR from the stated analytical limit of 40 percent RTP to 35.4 percent RTP. Rescaling the percent RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP. Additional detail on this change is described in Section 3.3.8 of this evaluation. Based on the above, the NRC staff concludes that this approach affords an equivalent level of protection to the CLB and is acceptable.

(4) From EPU LAR, Enclosure 5B, Section 4.1.10, TS Section 3.3.1.1, RPS Instrumentation, SR 3.3.1.1.23

This SR ensures that the OPRM is not bypassed under specified conditions. The licensee proposed to revise the value in the SR from 29% RTP to 26% RTP. This change is necessary for rescaling the OPRM trip-enabled region to maintain the same absolute power/flow region boundaries. This function was introduced into the GGNS TS via the GGNS PRNMS LAR. The 29 percent CLTP boundary is rescaled to the 26 percent EPU thermal power limit using the

CLTP/EPU ratio. This change updates the TS changes submitted as part of the PRNMS LAR to reflect EPU conditions. Additional detail is provided in Section 3.3.7 of this evaluation. Based on the above, the NRC staff concludes that this change is acceptable.

(5) From EPU LAR, Enclosure 5B, Section 4.1.10, TS Section 3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Function 2.b

The specified AV that is proposed to change is related to APRM Fixed Neutron Flux – High. The licensee proposed to modify the allowable value from 120% RTP to 119.3% RTP. The change ensures that adequate operating margin is maintained between the system setting and the analytical limit (122% RTP). Additional detail on the calculation of this value and the NRC staff's review of the calculation of the AV and NTSP are contained in Section 2.4.1.3.2 of this evaluation. Based on the above, the NRC staff concludes that this change is acceptable.

(6) From EPU LAR, Enclosure 5B, Section 4.1.10, TS Section 3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Function 2.d

These AVs are related to the APRM Flow Biased Simulated Thermal Power – High. The licensee proposed to revise the allowable value for the APRM Simulated Thermal Power High for two-loop operation from 0.65W + 62.9% RTP and $\leq$ 113% RTP to 0.58W + 59.1% RTP while maintaining the 113% RTP clamp and for one-loop operation from 0.65W + 42.3% RTP to 0.58W + 37.4% RTP. The licensee previously calculated this value for the PRNMS upgrade in the PRNMS LAR (Reference 123). The new value was calculated using the same methodology, and additional detail of the NRC staff's review of the calculation and methodology is contained in Section 3.3.3 of this evaluation. Based on the above, the NRC staff concludes that this approach is acceptable.

(7) From EPU LAR, Enclosure 5B, Section 4.1.10, TS Section 3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Function 2.f

This item addresses the applicable mode for the OPRM Upscale function. The licensee proposed to revise the OPRM Upscale Applicable Mode from the existing value of 24% RTP to 21% RTP. The change supports the requirement for the value to be 5 percent less than the OPRM trip enabled region boundary. This change updates the TS changes submitted as part of the PRNMS LAR to reflect EPU conditions. Section 3.3.7 of this evaluation contains additional detail on the NRC staff's review. Based on the above, the NRC staff concludes that this change is acceptable.

(8) From EPU LAR, Enclosure 5B, Section 4.1.10, TS Section 3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Function 5

This item addresses the applicable mode for the Reactor Vessel Water Level – High, Level 8 Function. The licensee proposed to revise the value in the SR from 25% RTP to 21.8% RTP. These values are nearly equivalent in terms of MWt (i.e., change from ~975 MWt to ~961 MWt). The revision to the percent RTP is based on the fuel thermal monitoring threshold (Section 2.8.2.1.2 of the PUSAR (Reference 57)). Based on the above, the NRC staff concludes that this change is acceptable.

(9) From EPU LAR, Enclosure 5B, Section 4.1.10, TS Section 3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Function 9

This item addresses the applicable mode for the Turbine Stop Valve Closure, Trip Oil Pressure - Low Function. The licensee proposed to revise the applicable modes or other specified conditions from 40% RTP to 35.4% RTP. The rationale for the change is the same as that cited in item (3) above, which the NRC staff concludes affords an equivalent level of protection to the CLB and is, therefore, acceptable.

(10) From EPU LAR, Enclosure 5B, Section 4.1.10, TS Section 3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Function 10

This item addresses the applicable mode for the Turbine Control Valve, Fast Closure, and Trip Oil Pressure - Low Function. The licensee proposed to revise the applicable modes or other specified conditions from 40 percent RTP to 35.4 percent RTP. The rationale for the change is the same as that cited in item (3) above, which the NRC staff concludes affords an equivalent level of protection to the CLB and is, therefore, acceptable.

(11) From EPU LAR, Enclosure 5B, Section 4.1.11, TS Section 3.3.4.1, EOC-RPT Instrumentation

This item addresses the applicability and LCO actions related to the End-of-Cycle (EOC) Recirculation Pump Trip (RPT) Instrumentation. The licensee proposed to revise the following sections of TS 3.3.4.1 from 40 percent RTP to 35.4 percent RTP.

- Applicability for TS 3.3.4.1 requires thermal power to be 40% RTP.
- Action C.2 requires thermal power to be reduced to less than 40% RTP.
- SR 3.3.4.1.5 requires verification that the Turbine Stop Valve Closure, Trip Oil Pressure – Low and Turbine Control Valve Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when thermal power 40% RTP.

The rationale for the change is the same as that cited in item (3) above. The NRC staff concludes that these changes are acceptable.

(12) From EPU LAR, Enclosure 5B, Section 4.1.11, TS Section 3.3.6.1, Primary Containment and Drywell Isolation Instrumentation, Table 3.3.6.1-1 Function 1.c

This change addresses the AV for the Main Steam Line Flow-High function. The licensee proposed to revise the value for this function from 176.5 psid to 255.9 psid. The change ensures that adequate operating margin is maintained between the system setting and the analytical limit. Further evaluation of this change is contained in Section 2.4.1.3.1 of this evaluation. The NRC staff concludes that this change is acceptable.

Conclusion

The NRC staff reviewed the licensee's application related to the effects of the proposed EPU on the functional design of the reactor trip system, engineered safety feature actuation system, safe-shutdown system, and control systems. The NRC staff concludes that the licensee 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. Furthermore, the NRC staff concludes that the systems will continue to meet the requirements of 10 CFR 50.55a(a)(1), 10 CFR 50.55(h), and GDCs 1, 5, 11, 12, 13, 14, 15, 19, 20, 22, 23, 25, 26, 40, and 42. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to instrumentation and controls.

Entergy had proposed a license condition as part of its EPU LAR submission, stating that GGNS will not operate at a thermal power above 3,898 MWt (i.e., the CLTP) until the PRNMS LAR is approved by the NRC. This evaluation assumed that the data provided in the EPU LAR for the PRNMS is confirmed during the review of the PRNMS. This license condition has been fulfilled as the PRNMS LAR, which was approved by Amendment No. 188 dated March 28, 2012 (Reference 121), and by letter dated April 26, 2012 (Reference 47), the licensee withdrew this license condition.

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

Regulatory Evaluation

The NRC staff reviews flood protection measures to ensure that SSCs important to safety are protected from flooding. The NRC staff's review covered flooding of SSCs important to safety from internal sources, such as those caused by failures of tanks and vessels. The NRC staff's review focused on increases of fluid volumes in tanks and vessels assumed in flooding analyses to assess the impact of any additional fluid on the flooding protection that is provided. The NRC's acceptance criteria for flood protection are based on GDC 2, "Design bases for protection against natural phenomena," and GDC 4, "Environmental and dynamic effects design bases."

Technical Evaluation

High Energy Line Breaks

The licensee's evaluation of GGNS's flood protection in regard to HELBs under EPU conditions was based on Sections 10.1 of the GE topical report, "Constant Pressure Power Uprate, Revision 4," which will be referred to as CLTR (Reference 55). The licensee's evaluation concluded that the fluid volumes in tanks and vessels will not increase following EPU implementation. The plant-specific HELB evaluations consider flooding from the entire volume of the condenser hotwell and condensate storage tank. These volumes would be unchanged at EPU conditions, so these evaluations remain acceptable. Since the licensee's analysis of flood protection shows that GDC 2 and GDC 4 will continue to be met for EPU conditions, the NRC staff concludes that the licensee's review is acceptable and does not require a further evaluation.

Moderate Energy Line Breaks

The licensee's evaluation of flood protection in regard to medium energy line breaks under EPU conditions was based on Section 10.2 of the CLTR. The licensee stated that three modifications are being implemented as a result of the EPU. A modification to the Auxiliary Cooling Tower System (ACTS) to add more tower cells over the existing basin and a modification of the circulating water pumps to increase the circulating water system (CWS) flow rate does increase the CWS inventory. The increase is stated to be marginal (less than 0.5 percent) in the total CWS volume with no changes in consequences. The licensee also stated that the modifications to the fuel pool cooling system do not affect existing internal flooding analyses because the system flow rate is unchanged.

Conclusion

The NRC staff has reviewed the flood protection analysis for GGNS and concludes that no significant changes are being made to the fluid volumes in tanks and vessels for the proposed EPU, and the modifications to moderate energy systems do not affect the consequences of evaluated flooding scenarios. The NRC staff concludes that SSCs important to safety will continue to be protected from flooding and will continue to meet the requirements of GDC 2 and 4 following implementation of the proposed EPU. Based on the above, the NRC staff concludes that the proposed EPU is acceptable with respect to flood protection.

2.5.1.1.2 Equipment and Floor Drains

Regulatory Evaluation

The function of the equipment and floor drainage system (EFDS) is to assure that waste liquids, valve and pump leak-offs, and tank drains are directed to the proper area for processing or disposal while preventing a backflow of water that might result from maximum flood levels to areas of the plant containing equipment that is important to safety. The EFDS also protects against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system. The NRC staff's review of the EFDS included the collection and disposal of liquid effluents outside containment. The NRC staff's review focused on any changes in fluid volumes or pump capacities that are necessary for the proposed EPU and are not consistent with previous assumptions with respect to floor drainage considerations. The NRC's acceptance criteria for the EFDS are based on GDC 2, "Design bases for protection against natural phenomena," and GDC 4, "Environmental and dynamic effects design bases," insofar as they require the EFDS to be designed to withstand the effects of earthquakes and to be compatible with the environmental conditions (flooding) associated with normal operation, maintenance, testing, and postulated accidents (pipe failures and tank ruptures).

Technical Evaluation

The licensee evaluation of GGNS plant equipment and floor drains was based on Section 8.1 of the CLTR. The licensee concluded that the plant changes resulting in increased water volumes and larger capacity pumps or piping systems have been adequately addressed. The expected increase of the EFDS collections of liquid waste is expected to be less than 1 percent.

The NRC staff evaluated the licensee's assessment of the EFDS according to GDC 2 and GDC 4 and concludes that the EFDS should have the capability to perform its existing functions during EPU conditions. The NRC staff concludes that the licensee's assessment is acceptable and does not require any further evaluation of the CWS.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EFDS and concludes that the licensee has adequately accounted for the plant changes resulting in increased water volumes and larger capacity pumps or piping systems. The NRC staff concludes that the EFDS has sufficient capacity to (1) handle the additional expected leakage resulting from the plant changes, (2) prevent the backflow of water to areas with safety-related equipment, and (3) ensure that contaminated fluids are not transferred to non-contaminated drainage systems. Based on the above, the NRC staff concludes that the EFDS will continue to meet the requirements of GDCs 2 and 4 following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the EFDS.

2.5.1.1.3 Circulating Water System

Regulatory Evaluation

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems. The NRC staff's review of the CWS focused on changes in flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed EPU. The NRC's acceptance criteria for the CWS are based on GDC 4, "Environmental and dynamic effects design bases," for the effects of flooding of safety-related areas due to leakage from the CWS and the effects of malfunction or failure of a component or piping of the CWS on the functional performance capabilities of safety-related SSCs. Specific review criteria are contained in SRP Section 10.4.5, "Circulating Water System" (Reference 62).

Technical Evaluation

The CWS provides a continuous supply of cooling water to the main condenser to remove the heat rejected by the turbine cycle and auxiliary systems. The NRC staff's review of the CWS focused on changes in existing flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed EPU. The CWS was evaluated in Section 2.5.1.1 for flood protection. The NRC's acceptance criteria for the CWS are based on GDC 4 for the effects of flooding of safety-related areas due to leakage from the CWS and the effects of malfunction or failure of a component or piping of the CWS on the functional performance capabilities of safety-related SSCs.

Conclusion

The NRC staff has reviewed the licensee's assessment of the CWS and concludes that the CWS will be able to perform its existing functions during EPU conditions. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the CWS.

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

Regulatory Evaluation

The NRC staff's review concerns missiles that could result from in-plant component overspeed failures and high-pressure system ruptures. The NRC staff's review of potential missile sources covered pressurized components and systems, and high-speed rotating machinery. The NRC staff's review was conducted to ensure that safety-related SSCs are adequately protected from internally generated missiles. In addition, for cases where safety-related SSCs are located in areas containing non-safety-related SSCs, the NRC staff reviewed the non-safety-related SSCs to ensure that their failure will not preclude the intended safety function of the safety-related SSCs.

The NRC staff's review focused on any increases in system pressures or component overspeed conditions that could result during plant operation, AOOs, or changes in existing system configurations such that missile barrier considerations could be affected. The NRC's acceptance criteria for the protection of SSCs important to safety against the effects of internally generated missiles that may result from equipment failures are based on GDC 4, "Environmental and dynamic effects design bases."

Technical Evaluation

The NRC staff reviewed the licensee's assessment and references for internally generated missiles and concluded that GGNS will continue to meet GDC 4, in which the effects of internally generated missiles will not impact the SSCs important to safety after EPU implementation. The missiles considered include those from rotating equipment failure and those from pressurized component failure. Internally generated missiles could be affected by the operating pressure of systems, the rotational speed of equipment and the introduction of new potential missile sources. The NRC staff did not find any alterations to the licensee's current analysis for internal missiles generation that would be affected for EPU conditions. The NRC staff concludes that the licensee's evaluation of internally generated missiles is acceptable.

Specifically, the licensee used Section 7.1 of the CLTR to evaluate the effect of the proposed EPU on the turbine generator, as related to the internal turbine missiles. Turbine missiles are evaluated in Section 2.5.1.2.2 of this SE. As stated in the EPU LAR, the licensee is replacing the high-pressure (HP) turbine. The design of the new HP turbine is of the monoblock rotor design. The licensee stated that the monoblock design does not increase the missile failure due to EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the internally generated missiles and the changes in system pressures and configurations that are required for the EPU. The NRC staff concludes that SSCs important to safety will be protected from internally generated missiles and will meet the requirements of GDC 4. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to internally generated missiles and conformance with GDC 4.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The large steam turbines of the main turbine generator (turbine generator) sets have the potential for producing large high-energy missiles, especially if the turbines should exceed their rated speed. The NRC staff's review of the turbine generator sets focuses on the effects of the proposed EPU on the turbine overspeed protection features to confirm that adequate turbine overspeed protection will continue to be maintained. The NRC's acceptance criteria for the turbine generator are based on GDC 4, "Environmental and dynamic effects design bases," and relates to protection of SSCs important to safety from the effects of turbine missiles by providing a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generating turbine missiles.

Technical Evaluation

The licensee used Section 7.1 of the CLTR (Reference 55) to evaluate the effect of the proposed EPU on the turbine generator for GGNS. The licensee stated that the turbine generator was originally designed with a flow margin of 5 percent. The current rated throttle steam flow is 15.97 million of pounds-mass per hour (Mlbm/hr) at a throttle pressure of 993 pounds per square inch absolute (psia). The generator is rated at 1,525 MVA, which results in a rated electrical output (gross) of 1,373 MWe at a power factor of 0.9 and a reactive power of 664 MVAR. At the EPU RTP and reactor dome pressure of 1,040 psia, the turbine operates at an increased rated throttle steam flow of 19.00 Mlbm/hr and at a throttle pressure of 951 psia. A flow margin of 4 percent is used in designing the new HP turbine section. The design point of the new turbine includes this flow margin in order to ensure that the turbine will be able to pass the rated throttle, as well as to allow sufficient margin for reactor pressure control.

The licensee stated that in order to meet these design parameters, the HP turbine and inner casing are being replaced with modified components. The valves wide open condition therefore refers to the turbine supply steam flow at 4 percent over rated condition (i.e., rated flow + 4 percent). For operation at EPU, the HP turbine has been redesigned with new diaphragms and buckets for at least the minimum target throttle flow margin, to increase its flow passing capability. The licensee provided a description of the HP turbine as follows:

> The replacement HP rotor is of a monoblock design. Monoblock rotors cause no increase in missile failure probability due to EPU. The LP [low-pressure] turbine rotors at GGNS have shrunk-on wheels with several design features to reduce the probability of SCC [stress corrosion cracking]. A missile probability analysis was performed in November 1998 when the LP rotors were replaced.
>
> The probability of turbine missile generation for GGNS is 3.00 x 10-6 per year per unit based on that turbine missile analysis. A review of the 1998 turbine missile analysis determined that its conclusions are still valid.

The licensee discussed the effect of the overspeed calculation for EPU conditions in the EPU LAR and determined that the entrapped steam energy will be increased. The hardware modification design to the turbine and its implementation process establishes the overspeed trip settings to provide turbine trip protection. The licensee concluded that the modification to the turbine for EPU operation will not result in increases in system pressures, configurations, or equipment overspeed that would impact the current analyses of internally generated missiles on safety-related or non-safety-related equipment. From previous EPU experience, the change in entrapped steam energy would have a small effect on peak overspeed.

The NRC staff concludes that the turbine generator will continue to meet GDC 4 in regard to maintaining its ability to minimize the probability of generating internal missiles that could impact SSCs important to safety by having adequate overspeed protection in place for EPU conditions.

Conclusion

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

2.5.1.3 Pipe Failures

Regulatory Evaluation

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

Technical Evaluation

The licensee used Sections 10.1 and 10.2 of the CLTR to evaluate the effect of the proposed EPU on the pipe failures for GGNS. The licensee evaluated the impact of the proposed EPU in two areas regarding pipe failures: (1) high-energy piping outside containment; (2) moderate energy piping outside containment.

In the analysis of high-energy piping outside containment, the licensee assessed that the EPU conditions would not cause any new HELB locations using the existing GGNS line break criteria. In addition, the licensee stated that there is no adverse effect on the post-HELB subcompartment structural integrity and minimal effects on environmental conditions outside the drywell caused by the EPU.

With respect to the moderate energy piping outside containment, the licensee stated the EPU does not affect the process parameters except for two modifications. The licensee stated that a modification to increase the flow rate of the CWS only affects the presently postulated circulating water break in the Turbine Building. The spray consequences from this break are not quantitatively evaluated because the Turbine Building does not contain safety-related equipment required to perform a shutdown following a DBA. The second modification to replace the FPCCS heat exchangers is stated not to increase the pressure in the CCW System, SSW system, or FPCCS.

The NRC staff reviewed the licensee's assessment of pipe failures according to GDC 4 and concludes that the EPU would not affect the protection of SSCs important to safety due to postulated pipe failures. Therefore, the NRC staff concludes that the area of pipe failures is acceptable for EPU conditions and a further evaluation is not required.

Conclusion

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

2.5.1.4 Fire Protection

<u>Regulatory Evaluation</u>

The purpose of the fire protection program (FPP) is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary 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 FPP are based on (1) 10 CFR 50.48, "Fire protection," insofar as it requires the development of a FPP to ensure, among other things, the capability to safely shutdown the plant; (2) GDC 3, "Fire protection," 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, "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. Specific review criteria are contained in Appendix D of SRP Section 9.5.1.1, "Fire Protection Program" (Reference 62), as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of RS-001 (Reference 54). GGNS was licensed to operate on November 1, 1984, and thus is not subject to Appendix R to 10 CFR Part 50. However, GGNS committed to follow certain separation requirements, contained in Appendix R, for redundant trains in the same fire area to the extent incorporated into its license condition. GGNS is a GE BWR design with Mark III containment.

The GGNS FPP describes the fire protection features of the plant necessary to comply with Branch Technical Position (BTP) Auxiliary and Power Conversion Systems Branch (APCSB) 9.5-1, Appendix A, dated August 23, 1976. The SER dated August 23, 1991 (Reference 131), describes the approved FPP for GGNS and is in listed in the GGNS operating license.

<u>Technical Evaluation</u>

Entergy developed the EPU LAR utilizing the guidelines in RS-001. In the EPU LAR, the licensee evaluated the applicable SSCs and safety analyses at the proposed EPU core power level of 4408 MWt. The NRC staff's review of the EPU LAR, Section 2.5.1.4.1, "Fire Protection Program," Attachment 5, to GNRO-2010/00056, identified areas in which additional information was necessary to complete the review of the proposed EPU LAR. By electronic mail dated January 26, 2011 (Reference 132), the NRC staff issued an RAI related to fire protection. By letter dated February 23, 2011 (Reference 4), Entergy provided its response, as discussed below.

In RAI #1 of Reference 132, the NRC staff noted that EPU LAR, Attachment 5B, to GNRO-2010/00056, "Safety Analysis Report for the Grand Gulf Nuclear Station Constant Pressure Power Uprate," Section 2.5.1.4.1, on page 2-194, states that, "*...Any changes in physical plant configuration or combustible loading as a result of modifications to implement the*

EPU will be evaluated in accordance with the plant modification and FPPs [fire protection programs]..."

The NRC staff stated that it was unclear whether there were FPP plant modifications planned (e.g., adding new cable trays, re-routing of existing cables, increases in combustible loading affecting fire barrier ratings, or changes to administrative controls) at EPU conditions. The NRC staff requested that the licensee clarify whether this request involved plant modifications or changes to the FPP, including any proposed modifications to implement EPU. If any, the NRC staff requested that the licensee to identify them and discuss their impact on the plant's compliance with the FPP licensing basis, 10 CFR 50.48, or applicable portions.

In its response dated February 23, 2011 (Reference 4), the licensee stated that there were several plant modifications that would affect safety-related areas of the plants. These modifications would add new cables to safety-related areas of the plant and, in some cases, involve using new or existing penetrations between rooms. Furthermore, the licensee stated that any increase from new combustible loadings would be small and would not affect the associated fire barrier rating. Affected penetrations are designed and sealed to maintain the required current fire barrier rating. All of these modifications are designed to be consistent with the current GGNS FPP such that there is no impact on the plant's compliance with the FPP licensing basis or 10 CFR 50.48.

The licensee's response satisfactorily addresses the NRC staff's concerns, and this RAI issue is considered resolved since the licensee indicated that for the EPU condition, several plant modifications in safety-related areas of the plant would result in changes to combustible loading and utilize new and existing penetrations between rooms. Since the changes in combustible loading have no impact on the existing fire barrier rating or the overall approved FPP and the penetration seals will maintain fire barrier rating, the NRC staff concludes that the response acceptable.

In RAI #2, the NRC staff stated that the results of the Appendix R evaluation for CLTP and EPU are provided in Table 2.5-1 and Figures 2.5-1 through 2.5-6 of the PUSAR. The NRC staff noted in Table 2.5-1 that at EPU conditions, there is an increase in the suppression pool bulk temperature to 181.4 °F, 7.5 °F above the current suppression pool bulk temperature of 173.9 °F. The NRC staff inquired whether or not the GGNS safe shutdown instructions credit any operator manual action in the containment. If any, the NRC staff requested that the licensee discuss how this operator manual action can be accomplished within the available time at higher suppression pool bulk temperature (e.g., manually opening the main steam relief valves).

In its response, the licensee stated that the GGNS safe shutdown instructions do not credit any manual operator actions in containment.

The licensee's response satisfactorily addresses the NRC staff's concerns, and this RAI issue is considered resolved based on the following: For the EPU conditions, the licensee clarified that there are no manual operator actions credited in containment.

In RAI #3, the NRC staff stated that some plants credit aspects of their fire protection systems for other than fire protection activities (e.g., utilizing the fire water pumps and water supply as backup cooling or inventory for non-primary reactor systems). If GGNS credits its fire protection system in this way, the NRC staff requested that the EPU LAR identify the specific situations and discuss to what extent, if any, the EPU affects these "non-fire-protection" aspects of the plant fire protection system. If the GGNS does not take such credit, the NRC staff requested that the licensee verify this as well.

The NRC staff further requested that the licensee discuss how any non-fire suppression use of fire protection water will impact the need to meet the fire protection system design demands.

In its response, the licensee stated that the GGNS does not credit the fire protection system to support the design basis for non-fire protection functions. Further, the fire protection system is considered a potential backup water source only for beyond design-basis events that involve inadequate decay heat removal capability or the need for transfer of water inventory. Therefore, there are no non-fire suppression uses of the system that could impact the system's demands during DBAs.

The NRC staff reviewed the licensee's clarification on the use of fire protection water/systems for non-fire protection functions, including whether such use could impact the need to meet the fire protection system design demands. The NRC staff concludes that the licensee's response to the RAI is acceptable because (1) GGNS does not credit the fire protection system to support the design basis for non-fire protection functions, and (2) there are no non-fire protection uses of the system that could impact the system's demands during DBAs.

Based on the above, the NRC staff concludes that the licensee has adequately accounted for the effects of the 13.1 percent increase in decay heat on the ability of the required systems to achieve and maintain safe shutdown conditions. The NRC staff concludes that this aspect of the capability of the associated fire protection SSCs to perform their design basis functions at an increased core power level of 4408 MWt is acceptable with respect to fire protection.

Conclusion

Based on the above, NRC staff concludes that the proposed EPU will not have a significant impact on the FPP or post-fire safe shutdown capability and, therefore, the proposed amendment is acceptable.

2.5.2 Fission Product Control

2.5.2.1 Fission Product Control Systems and Structures

Regulatory Evaluation

The review for fission product control systems and structures covered the basis for developing the mathematical model for DBLOCA dose computations, the values of key parameters, the applicability of important modeling assumptions, and the functional capability of ventilation systems used to control fission product releases. The review primarily focused on any adverse effects that the proposed EPU may have on the assumptions used in the analyses for control of fission products. The regulatory acceptance criteria are based on GDC 41, "Containment atmosphere cleanup," insofar as it requires that the containment atmosphere cleanup system be provided to reduce the concentration of fission products released to the environment following postulated accidents.

Technical Evaluation

The licensee used Section 4.5 of the CLTR to evaluate the effect of the proposed EPU on the standby gas treatment system (SGTS) filters and charcoal filters for GGNS. The licensee stated that neither the SGTS filters nor the filter materials are affected by the EPU. The increase in CTP proportionally increases the core iodine inventory. However, the licensee stated that there is sufficient charcoal mass present so that the post-LOCA iodine loading on the charcoal remains below safety limits outlined in NRC Regulatory Guide (RG) 1.52, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," June 2001 (Reference 133).

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SGTS filters and charcoal filters and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on fission control. The NRC staff concludes that the SGTS filters and charcoal filters will continue to provide adequate fission control and will continue to meet the requirements of GDC 41 following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the SGTS filters and charcoal filters.

2.5.2.2 Main Condenser Evacuation System

Regulatory Evaluation

The main condenser evacuation system (MCES) generally consists of two subsystems: (1) the "hogging" or startup system which initially establishes main condenser vacuum and (2) the system which maintains condenser vacuum once it has been established. The NRC staff's review focused on modifications to the system that may affect gaseous radioactive material handling and release assumptions, and design features to preclude the possibility of an explosion (if the potential for explosive mixtures exists). The NRC's acceptance criteria for the MCES are based on (1) GDC 60, "Control of releases of radioactive materials to the environment," insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) GDC 64, "Monitoring radioactivity releases," insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs and postulated accidents.

Technical Evaluation

The licensee used Section 7.2 of the CLTR to evaluate the effect of the proposed EPU on the MCES for GGNS. The licensee indicated during its review of the MCES that the design of the condenser air removal system will not be adversely affected by EPU and no modification to the

MCES will be required. The licensee evaluated three areas of the condenser air removal system to make its assessment:

- Non-condensable gas flow capacity of the steam jet air ejector (SJAE) system;
- Capability of the SJAEs to operate satisfactorily with available dilution / motive steam flow;
- Mechanical vacuum (hogging) pump capability to remove required non-condensable gases from the condenser at EPU start-up conditions.

The licensee indicated that the physical size of the primary condenser and evacuation time remain unchanged in establishing the capabilities of the vacuum pumps under EPU conditions. Also, the licensee indicated the holdup time in the pump discharge line does not change and the SJAEs are capable for handling operational flows at EPU conditions.

Conclusion

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

2.5.2.3 Turbine Gland Sealing System

Regulatory Evaluation

The turbine gland sealing system (TGSS) is provided to control the release of radioactive material from steam in the turbine to the environment. The NRC staff reviewed changes to the TGSS with respect to factors that may affect gaseous radioactive material handling (e.g., source of sealing steam, system interfaces, and potential leakage paths). The NRC's acceptance criteria for the TGSS are based on (1) GDC 60, "Control of releases of radioactive materials to the environment," insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) GDC 64, "Monitoring radioactivity releases," insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs and postulated accidents.

Technical Evaluation

The licensee evaluated the TGSS and found that no modifications are needed to support EPU conditions. The NRC staff did not find any concerns with the licensee's assessment with the TGSS and the functionality of the TGSS during EPU operations should continue to meet the criteria of GDC 60 and GDC 64. Therefore, the NRC staff concludes that the TGSS is acceptable for EPU conditions.

Conclusion

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

2.5.2.4 Main Steam Isolation Valve Leakage Control System

Regulatory Evaluation

Redundant quick-acting isolation valves are provided on each MSL. The leakage control system (LCS) is designed to reduce the amount of direct, untreated leakage from the main steam isolation valves (MSIVs) when isolation of the primary system and containment is required. The review of the MSIV LCS focused on the effects of the proposed EPU on the amount of leakage assumed to occur. The regulatory acceptance criteria for the MSIV LCS are based on GDC 54, "Piping systems penetrating containment," insofar as it requires that piping systems penetrating containment be provided with leakage detection and isolation capabilities.

Technical Evaluation

The licensee used Section 4.6 of the CLTR (Reference 55) to evaluate the effect of the proposed EPU on the MSIV LCS for GGNS. The licensee evaluated the MSIV LCS and found that no modifications are needed to support EPU conditions. The NRC staff did not find any concerns with the licensee's assessment with the MSIV LCS and the functionality of the MSIV LCS during EPU operations should continue to meet the criteria of GDC 54. Therefore, the NRC staff concludes that the MSIV LCS is acceptable for EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the MSIV Leakage Control System and concludes that the licensee has adequately evaluated the system. The NRC staff concludes that the MSIV LCS will continue to adequately account for the assumed leakage through the MSIV consistent with GDC 54. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the MSIV Leakage Control System.

2.5.3 Component Cooling and Decay Heat Removal

2.5.3.1 Spent Fuel Pool Cooling and Cleanup System

Regulatory Evaluation

The spent fuel pool (SFP) provides wet storage of spent fuel assemblies. The safety function of the fuel pool cooling and cleanup system (FPCCS) is to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. The review for the proposed EPU focused on the effects of the proposed EPU on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions. The regulatory acceptance criteria for the FPCCS are based on: (1) 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; (2) GDC 44, "Cooling water," insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided; and (3) GDC 61, "Fuel storage and handling and radioactivity control," insofar as it requires that fuel storage systems be designed with residual heat removal (RHR) capability reflecting the importance to safety of DHR, and measures to prevent a significant loss of fuel storage coolant inventory under accident conditions. Section 9.1.3.1.1 of the licensee's UFSAR has a design basis to maintain spent fuel temperature at or below 150 °F.

<u>Technical Evaluation</u>

The licensee used Section 6.3.1 of the CLTR (Reference 55) to address the effect of the EPU on the FPCCS. The licensee stated that an increase of 15 percent due to EPU results in a 15 percent increase of decay heat generated in FPCCS. In its letter dated November 18, 2011 (Reference 2), the licensee stated that the EPU evaluation is based on a full fuel pool and considers a reload batch of 380 bundles as a result of the EPU and the planned future transition to 24-month fuel cycles; the larger batch extends the discharge time from 150 to 173 hours. As a result, the peak pool heat load increases from 19.06 million British Thermal Units (BTUs) per hour (MBTU/hr) at 150 hours of decay (pre-EPU) to 27.4 MBTU/hr at 173 hours after shutdown (post-EPU). The modification to the FPCCS involves the replacement of the current heat exchangers with two plate and frame heat exchangers and any necessary support auxiliaries. The licensee also stated that the FPCCS can maintain the SFP the 150 °F temperature alone in EPU conditions. The RHR system is also capable of maintaining the SFP below 140 °F with an assumed 90 °F station service water (SSW) temperature. The RHR system may be necessary in the early stages of full core offload to maintain the 150 °F limit specified in the UFSAR.

The licensee stated no single active failure of the FPCCS equipment or components will cause an inability to: 1) maintain irradiated fuel submerged in water; 2) re-establish normal fuel pool water level; or 3) remove decay heat from the pool.

In accordance with the CLTR Section 6.3.2, the licensee evaluated the crud activity and corrosion products and has determined that the resulting increase is insignificant to safety.

In accordance with the CLTR Section 6.3.3, the licensee evaluated the normal radiation levels expected around the spent fuel pool and has determined that the resulting increase is insignificant to safety.

Section 6.3.4 of the CLTR made a generic determination that the spent fuel storage racks are unaffected by the increase in decay heat load associated with the power uprate, provided the licensing limits on spent fuel pool temperature are maintained. Since the modifications to the spent fuel pool cooling and cleanup system allow the existing temperature limits to be maintained, the storage racks are unaffected by the uprate.

The NRC staff reviewed the licensee's assessment of the FPCCS according to GDC 5, GDC 44, and GDC 61 and concludes that the impact of EPU operation on the systems and components that utilize the FPCCS will not affect their capabilities to perform their safety functions. The NRC staff concludes that the licensee's assessment is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the FPCCS and concludes that the licensee has adequately accounted for the increased heat loads on system performance that would result from the proposed EPU. The NRC staff concludes that the FPCCS will continue to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. Therefore, the NRC staff has determined that the FPCCS will continue to meet the requirements of GDC 5, GDC 44, and GDC 61. Based on the above, the NRC staff concludes that the proposed EPU is acceptable with respect to the FPCCS.

2.5.3.2 Station Service Water System

Regulatory Evaluation

At GGNS, service water for cooling safety-related equipment is provided by the SSW. The plant service water (PSW) system provides makeup water to the SSW. The review covered the SSW components with respect to their functional performance as affected by adverse operational (i.e., water hammer) conditions, abnormal operational conditions, and accident conditions (e.g., a LOCA with the LOOP). The review focused on the additional heat load that would result from the proposed EPU. The regulatory acceptance criteria are based on: (1) 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; (2) 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 (3) GDC 44, "Cooling water," insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided.

Technical Evaluation

The licensee used Section 6.4 of the CLTR (Reference 55) to address the effect of the EPU on the service water system (SWS). The licensee describes the SWS as being comprised of two systems, the non-safety-related PSW system and safety-related SSW system. The PSW system provides once through cooling water from radial (Ranney) wells to various non-safety-related plant systems and components. The radial (Ranney) well system consists of four wells, pumps, recirculation line at each well, valves, instrumentation, and piping. An additional radial well has been installed at GGNS to supplement the existing system. The new well will provide additional operating margin and will allow plant availability to be maintained when another well is out of service. The PSW system is designed to operate during normal conditions. The safety-related portion of the PSW system includes some piping and (safety-related to non-safety-related) isolation valves. The SSW system includes pumps, valves, piping, and instrumentation to provide cooling water from the standby cooling tower to various safety-related plant systems and components. The SSW is safety-related and is designed to operate during normal shutdown, LOOP, transient, and post-accident conditions.

The licensee identified the following heat load increases that will be the direct result of the EPU:

- RHR System Heat Exchangers
- SFP Cooling Water Heat Exchangers (safety-related backup to normal non-safety-related CCW supply)

The licensee identified the following heat load increases that will be the indirect result of the EPU:

- RHR Pumps A/B/C Pump Room Coolers
- Reactor Core Isolation Cooling (RCIC) Pump Room Cooler
- High Pressure Coolant Spray (HPCS) Pump Room Cooler
- Low Pressure Coolant Spray (LPCS) Pump Room Cooler
- SFP Cooling Water Pump Room Coolers
- ESF Electrical Switchgear Room Coolers

The licensee also identified services for which heat loads are not dependent on Reactor Temperature and Pressure:

- Division I, II, and HPCS Standby Diesel Generator Jacket Water Coolers
- RHR Pumps Seal Coolers (safety-related backup to normal non-safety-related CCW supply)
- SSW Pumps A/B Motor Bearing Coolers

The licensee stated that the capacity of the Ultimate Heat Sink (UHS) (Standby Cooling Tower) is being increased by 15 percent. This increase is equal to the proposed power increase and addresses the increased heat loads associated with the EPU. A discussion of the UHS modifications can be found in Section 2.5.3.4 of this SE. Long-term cooling is addressed in Section 7.8 this SE. Since the cooling capacity increase is equal to the proposed power increase, the cooling capacity remains adequate.

The NRC staff reviewed the licensee's assessment of the SWS according to GDC 4, GDC 5, and GDC 44 and concludes that the impact of EPU operation on the systems and components that utilize the SWS will not affect their capabilities to perform their safety functions, especially in the event of accident scenarios such as a LOCA. With the proposed modifications the increased heat can be maintained within limits. The NRC staff concludes that the licensee's assessment is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the SWS and concludes that the licensee has adequately accounted for the increased heat loads on system performance that would result from the proposed EPU and that the SWS will provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, the NRC staff has determined that the station SWS will continue to meet the requirements of GDC 4, GDC 5, and GDC 44. Based on the above, the NRC staff concludes that the proposed EPU is acceptable with respect to the station SWS.

2.5.3.3 Reactor Auxiliary Cooling Water Systems

Regulatory Evaluation

The review covered reactor auxiliary cooling water systems that are required for: (1) safe shutdown during normal operations, abnormal operating occurrences, and mitigating the consequences of accident conditions; or (2) preventing the occurrence of an accident. These systems include closed-loop auxiliary cooling water systems for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the ECCS. The review covered the capability of the auxiliary cooling water systems to provide adequate cooling water to safety-related ECCS components and reactor auxiliary equipment for all planned operating conditions. Emphasis was placed on the cooling water systems for safety-related components (e.g., ECCS equipment, ventilation equipment, and reactor shutdown equipment). The review focused on the additional heat load that would result from the proposed EPU. The regulatory acceptance criteria for the reactor auxiliary cooling water system are based on: (1) 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 attendant loads (i.e., water hammer), maintenance, testing, and postulated accidents; (2) 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 (3) GDC 44, "Cooling water," insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided.

Technical Evaluation

The licensee used Section 6.4 of the CLTR (Reference 55) to address the effect of the EPU on the reactor auxiliary cooling water systems. The three systems evaluated in the EPU LAR for EPU are the component cooling water (CCW), turbine building cooling water (TBCW), and the drywell chilled water (DCW) systems.

The licensee stated that the CCW piping and valves associated with SFP heat exchangers and piping and valves that form part of the containment boundary are safety-related. EPU does not affect the ability of these pipes and valves to perform their intended safety-related function. The rest of the CCW system is non-safety-related and is not intended to operate during accident conditions. The licensee stated that the only significant increase in heat load due to EPU is an increase in FPCCS heat load. Safety-related cooling for the SFP is provided by the SSW and not the CCW system.

The licensee stated that the TBCW system is a non-safety-related closed cooling water system which cools auxiliary plant equipment during normal plant operation. The licensee stated that the failure of the system will not compromise any safety-related system or component and will not prevent safe reactor shutdown. The system normal capacity is 141.4 MBTU/hr, which is unaffected by EPU. The licensee stated that the increase in heat load of the TBCW system can be accommodated by the margin in the system heat exchangers, and the system pumps have sufficient capacity to accommodate any minor flow increases from potential changes in localized flows to affected components, as required.

The anticipated increase of the heat loads on the DCW system is stated to have sufficient redundancy to ensure adequate heat removal during normal conditions.

The NRC staff reviewed the licensee's assessment of the reactor auxiliary cooling water systems according to GDC 4, GDC 5, and GDC 44 and concludes that the impact of EPU operation on the systems and components that utilize the reactor auxiliary cooling water systems will not affect their capabilities to perform their safety functions, especially in the event of accident scenarios such as a LOCA. With the proposed modifications the increased heat can be maintained within limits. The NRC staff concludes that the licensee's assessment is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the reactor auxiliary cooling water systems and concludes that the licensee has adequately accounted for the increased heat loads on system performance that would result from the proposed EPU. The NRC staff concludes that all the reactor auxiliary cooling water systems will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, the NRC staff concludes that the station reactor auxiliary cooling water systems will continue to meet the requirements of GDC 4, GDC 5, and GDC 44. Based on the above, the NRC staff concludes that the proposed EPU is acceptable with respect to the station reactor auxiliary cooling water systems.

2.5.3.4 Ultimate Heat Sink

Regulatory Evaluation

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

Technical Evaluation

The licensee used Section 6.4 of the CLTR (Reference 55) to address the effect of the proposed EPU on the UHS. The licensee provided the following description of the UHS.

> The Ultimate Heat Sink (UHS) consists of two four-cell mechanical draft cooling towers and two concrete makeup water basins of the Standby Service Water (SSW) System. One tower services one Residual Heat Removal (RHR) train and other safety-related loads on Division I with two fan cells, and the High Pressure Core Spray (HPCS) cooling loads (Division III) with the remaining two cells. The other tower services the second RHR train and safety-related cooling loads on Division II with two fan cells (two cells are not utilized.) The SSW cooling towers are the safety-related source of cooling water during accident and loss of offsite power (LOOP) conditions.

The licensee stated that during a refueling outage in the spring of 2010, additional capacity was added to the cooling tower cells to increase the heat removal capability. This modification involved replacement of the original ceramic block fill material with high efficiency stainless steel fill material. In response to an NRC staff RAI, the licensee provided the evaluation for the modified design in regards to the increased anticipated heat load of the EPU. The licensee stated that the peak heat load increase due to EPU has been analyzed to be less than 6 percent above original design conditions. The licensee anticipates the UHS CWT (SSW supply temperature to the plant) would be 88.9 °F, which is less than the 90 °F maximum temperature in the CLB. Since the cooling capacity increase is equal to the proposed power increase, the cooling capacity remains adequate.

The NRC staff reviewed the licensee's assessment of the UHS according to GDC 5 and GDC 44 and concludes that the impact of EPU operation on the systems and components that utilize the UHS will not affect their capabilities to perform their safety functions, especially in the event of accident scenarios such as a LOCA. With the proposed modifications the increased heat can be maintained within limits. The NRC staff concludes that the licensee's assessment is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the UHS and concludes that the licensee has adequately accounted for the increased heat loads on system performance that would result from the proposed EPU. The NRC staff concludes that all the UHS will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed EPU. Therefore, the NRC staff concludes that the station UHS will continue to meet the requirements of GDC 5 and GDC 44. Based on the above, the NRC staff concludes that the proposed EPU is acceptable with respect to the station UHS.

2.5.4 Balance-of-Plant Systems

2.5.4.1 Main Steam and Reheat System

Regulatory Evaluation

The main steam and reheat system (MSRS) transports steam from the nuclear steam supply system to the power conversion system and various safety-related and non-safety-related auxiliaries. The review focused on the effects of the proposed EPU on the system's capability to transport steam to the power conversion system, provide heat sink capacity, supply steam to drive safety system pumps, and withstand adverse dynamic loads (e.g., water steam hammer resulting from rapid valve closure and relief valve fluid discharge loads). The regulatory acceptance criteria for the MSRS are based on: (1) GDC 4, "Environmental and dynamic effects design bases," insofar as it requires that SSCs important to safety be protected against dynamic effects, including the effects of missiles, pipe whip, and jet impingement forces associated with pipe breaks; and (2) 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.

Technical Evaluation

The licensee used Sections 3.4.1 and 3.7 of the CLTR (Reference 55) to address the effect of proposed EPU on FIV in the MSL and MSL flow restrictors. The licensee indicated that the main steam piping pressures and temperatures are not affected by EPU. The licensee also indicated that seismic inertia loads, seismic building displacement loads, and SRV discharge loads are not affected by EPU. The increase in main steam flow results in increased forces from the turbine stop valve closure transient. However, the turbine stop valve closure loads bound the MSIV closure loads because the MSIV closure time is significantly longer than the turbine stop valve closure time.

The licensee also assessed the MSRS for increased MSL flow, which may affect vibration of the piping during normal operation. The vibration frequency, extent, and magnitude depend upon plant-specific parameters, valve locations, the valve design, and piping support arrangements. The FIV of the piping will be addressed by vibration testing during initial plant operation at the higher steam flow rates for EPU operation. [[

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The NRC staff reviewed the licensee's assessment of the MSRS according to GDC 4 and GDC 5 and did not find any implications that would allow the main steam system to negatively impact the SSCs important to safety at EPU conditions. The current analysis for normal and accident scenarios remain unchanged for EPU conditions and no modifications to the main steam system is needed to support EPU operation. Therefore, the NRC staff concludes that the licensee assessment of the main steam is acceptable for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the MSRS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MSRS. The NRC staff concludes that the MSRS will maintain its ability to transport steam to the power conversion system, provide heat sink capacity, supply steam to steam-driven safety pumps, and withstand steam hammer. The NRC staff further concludes that the MSRS will continue to meet the requirements of GDC 4 and GDC 5. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the MSRS.

2.5.4.2 Main Condenser System

Regulatory Evaluation

The main condenser (MC) system 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 review focused on the effects of the proposed EPU on the steam bypass capability with respect to load rejection assumptions, and on the ability of the MC system to withstand the blowdown effects of steam from the TBS. The regulatory acceptance criteria for the MC system are based on GDC 60, "Control of releases of radioactive materials to the environment," insofar as it requires that the plant design include means to control the release of radioactive effluents.

Technical Evaluation

The licensee used Section 7.2 of the CLTR (Reference 55) to address the effect of the proposed EPU on the MC. The licensee stated:

> EPU operation decreases the margin for the MC storage capacity from approximately 92 seconds at CLTP to 79 seconds at EPU. MC storage capacity is less than the original design objective of 90 second holdup time for the decay of short-lived radioactive isotopes. However, this reduction of condensate retention time will have no significant effect on the radiation level in the MC area because the major source is the N-16 activity in the MC exhaust steam. In addition, the small reduction in the condensate retention time will not significantly affect the radiation source in the Condensate Demineralizers and the feedwater system, because the major source in these systems is radioiodines, which have half-lives much longer than the reduction in the condensate retention time in the hotwell.

The NRC staff evaluated the licensee's assessment of the MC system according to GDC 60 and concludes that the MC will continue to perform its function in controlling the release of radioactive effluents within the system's design capability. No changes are being made to the MC to support EPU operation and the MC ability to handle increased heat due to EPU operation remains within system design capability. Therefore, the NRC staff concludes that the licensee's assessment of the MC system is acceptable for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the MC system and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MC system. The NRC staff concludes that the MC system will continue to maintain its ability to withstand the blowdown effects of the steam from the TBS and thereby continue to meet GDC 60 with respect to controlling releases of radioactive effluents.

Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the MC system

2.5.4.3 Turbine Bypass System

Regulatory Evaluation

The turbine bypass system (TBS) is designed to discharge a stated percentage of rated main steam flow directly to the MC system, bypassing the turbine. This steam bypass enables the plant to take step-load reductions up to the TBS capacity without the reactor or turbine tripping. The system is also used during startup and shutdown to control reactor pressure. The review of the TBS focused on how it affects the load rejection capability at EPU, analysis of postulated system piping failures, and the consequences of inadvertent TBS operation. The regulatory acceptance criteria for the TBS are based on: (1) 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 (including pipe breaks or malfunctions of the TBS); and (2) GDC 34, "Residual heat removal," insofar as it requires that a RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core at a rate such that SAFDLs and the design conditions of the RCPB are not exceeded.

Technical Evaluation

The licensee used Section 7.3 of the CLTR (Reference 55) to address the effect of the proposed EPU on the TBS. The licensee stated that each of three bypass valves is designed to pass a steam flow of 1.92 Mlbm/hr, resulting in a system bypass capacity of 5.77 Mlbm/hr. The licensee also stated the bypass capacity in terms of mass flow is not changed due to EPU. At EPU conditions, the bypass capacity at GGNS remains adequate for normal operational flexibility at EPU RTP.

The NRC staff evaluated the licensee's assessment of the TBS according to GDC 4 and GDC 34 and did not find any system modifications or changes to the operation of the TBS that would be impacted by EPU implementation. The TBS capability to handle steam bypass from the turbine remains unchanged for EPU conditions. The NRC staff concludes that the licensee's assessment of the TBS is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the TBS. The NRC staff concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the TBS. The NRC staff concludes that the TBS failures will not adversely affect essential SSCs. The NRC staff concludes that the TBS will continue to meet GDC 4 and GDC 34. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the TBS.

2.5.4.4 Condensate and Feedwater

Regulatory Evaluation

The condensate and feedwater system (CFS) provides feedwater at a particular temperature, pressure, and flow rate to the reactor. The review focused on how the proposed EPU affects previous analyses and considerations with respect to the capability of the CFS to supply adequate feedwater during plant operation and shutdown, and isolate components, subsystems, and piping in order to preserve the system's safety function. The regulatory acceptance criteria for the CFS are based on: (1) 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 possible fluid flow instabilities (e.g., water hammer), maintenance, testing, and postulated accidents; (2) 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 (3) GDC 44, "Cooling water," insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and that the system be provided with suitable isolation capabilities to assure the safety function can be accomplished with electric power available from only the on-site system or only the off-site system, assuming a single failure.

Technical Evaluation

The licensee used Section 7.4 of the CLTR (Reference 55) to address the effect of proposed EPU on the CFS. The licensee described the CFS in the EPU LAR as being able to provide a reliable supply of feedwater at the temperature, pressure, quality, and flow rate as required by the reactor. The performance of the CFS has a major effect on plant availability and capability to operate at EPU conditions. In the EPU LAR, the licensee listed non-safety-related equipment that will be modified to support EPU operation, which include:

- RFP turbines
- Condensate full flow filtration (CFFF) with automatic bypass capability
- Low pressure feedwater heaters replacement

RFP Turbines

The licensee stated the overspeed setpoint on the RFP turbines will be increased to accommodate the increased speed demand for normal operations. The RFP is tripped on high discharge pressure which prevents pump operation at shutoff-head conditions.

CFFF

The licensee stated that a CFFF system is being installed upstream of the condensate booster pumps resulting in a reduced available pressure at pump suction. In addition, the licensee stated that an automatic bypass around the CFFF system will be included in the modification.

Low Pressure Feedwater Heater Replacement

After an evaluation was performed, the licensee determined that stages 1, 5 and 6 heaters were verified to be acceptable for the higher feedwater heater flows, temperatures and pressures for EPU. Stages 2, 3, and 4 heaters are being replaced to accommodate the increased flows demands of the EPU.

The NRC staff evaluated the licensee's assessment of the CFS according to GDC 4, GDC 5, and GDC 44 and concludes that the EPU operation will not prevent the CFS from performing its normal and transient functions, provided that the licensee make the evaluated changes to the CFS equipment prior to EPU implementation. The modifications to the CFS do not prevent the system from withstanding a water hammer or lead to the failure of SSCs important to safety. The NRC staff concludes that the licensee's assessment of the CFS is acceptable for EPU operation.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the CFS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the CFS. The NRC staff concludes that the CFS will continue to maintain its ability to satisfy feedwater requirements for normal operation and shutdown, withstand water hammer, maintain isolation capability in order to preserve the system safety function, and not cause failure of safety-related SSCs. The NRC staff further concludes that the CFS will continue to meet the requirements of GDC 4, GDC 5, and GDC 44. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the CFS.

2.5.5 Waste Management Systems

2.5.5.1 Gaseous Waste Management Systems

<u>Regulatory Evaluation</u>

The 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 the condenser air removal system; the gland seal exhaust and the mechanical vacuum pump operation exhaust; and the building ventilation system exhausts. The review focused on the effects that the proposed EPU may have on: (1) the design criteria of the GWMS; (2) methods of treatment; (3) expected releases; (4) principal parameters used in calculating the releases of radioactive materials in gaseous effluents; and (5) design features for precluding the possibility of an explosion if the potential for explosive mixtures exists. The regulatory acceptance criteria for GWMS are based on: (1) 10 CFR 20.1302, "Compliance with dose limits for individual members of the public," insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC 3, "Fire protection," insofar as it requires that (a) SSCs important to safety be designed and located to minimize the probability and effect of fires, (b) noncombustible and heat resistant materials be used, and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; (3) GDC 60, "Control of releases of radioactive materials to the environment," insofar as it requires that the plant design include means to control the release of radioactive effluents; (4) GDC 61, "Fuel storage and handling and radioactivity control," insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (5) Appendix I, "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion 'As Low as is Reasonably Achievable' for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," to 10 CFR Part 50, Sections II.B, II.C, and II.D, which set numerical guides for design objectives and LCOs to meet the "as low as is reasonably achievable" (ALARA) criterion.

Technical Evaluation

The licensee used Section 8.2 of the CLTR (Reference 55) to address the effect of proposed EPU on the GWMS. The licensee described in the EPU LAR that the primary function of the GWMS is to process and control the release of gaseous radioactive effluents to the site environs so that the total radiation exposure of persons in offsite areas is within the guideline values of 10 CFR 50, Appendix I.

The CLTP design-basis radiolytic gas production rate is 0.067 cubic feet per minute per MWt (cfm/MWt). The normal operation radiolytic gas production rate is expected to increase by approximately 13 percent due to EPU. The increase of 13 percent equates to an radiolytic gas production rate of 0.044 cfm/MWt. The licensee stated that the recombiner and condenser, as well as downstream system components are designed to handle the increase in the internal power of the EPU. The licensee determined that the CLTP design basis will maintained for EPU operation and that all structures, systems, and components of the offgas system were acceptable for EPU operation.

The licensee also stated that the GWMS design criteria will ensure that it will meet the plant licensing basis for controlling gaseous waste such that the total radiation exposure of persons in offsite areas will be within the applicable guideline values of 10 CFR 20.1302; Appendix I to 10 CFR Part 50; and the Environmental Protection Agency's regulations at 40 CFR 190, "Environmental Radiation Protection Standards for Nuclear Power Operations."

The NRC staff has reviewed the licensee's assessment of the GWMS according to the requirements of 10 CFR 20.1302; GDC 3, GDC 60, and GDC 61; and Appendix I to 10 CFR Part 50, Sections II.B, II.C, and II.D. The NRC staff concludes that the GWMS will continue to perform its design safety functions during EPU operations and the current design capability of the GWMS is capable of handling the effects of the EPU. Therefore, the NRC staff concludes that the licensee assessment of the GWMS is acceptable for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the GWMS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of gaseous waste on the abilities of the systems to control releases of radioactive materials and preclude the possibility of an explosion if the potential for explosive mixtures exists. The NRC staff concludes that the GWMS will continue to meet their design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the GWMS will continue to meet the requirements of 10 CFR 20.1302; GDC 3, GDC 60, and GDC 61; and 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the GWMS.

2.5.5.2 Liquid Waste Management Systems

Regulatory Evaluation

The review of liquid waste management systems (LWMS) focused on the effects that the proposed EPU may have on previous analyses and considerations related to the LWMS' design, design objectives, design criteria, methods of treatment, expected releases, and principal parameters used in calculating the releases of radioactive materials in liquid effluents. The regulatory acceptance criteria for the LWMS are based on: (1) 10 CFR 20.1302, "Compliance with dose limits for individual members of the public," insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC 60, "Control of releases of radioactive materials to the environment," insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) GDC 61, "Fuel storage and handling and radioactivity control," insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (4) Appendix I, "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion 'As Low as is Reasonably Achievable' for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," to 10 CFR Part 50, Sections II.A and II.D, which set numerical guides for dose design objectives and LCOs to meet the ALARA criterion.

Technical Evaluation

The licensee used Section 8.1 of the CLTR (Reference 55) to address the effect of proposed EPU on the LWMS. The licensee described in the EPU LAR that the primary effect of EPU on the LWMS is a result of the increased load on the condensate demineralizers. The licensee stated that the increased condensate demineralizer loads are expected to increase the volume of liquid waste processed by the LWMS due to EPU by less than 1 percent, which will not impact the capacity of the LWMS.

The NRC staff has reviewed the licensee's assessment of the LWMS according to requirements of 10 CFR 20.1302; GDC 60 and GDC 61; and 10 CFR Part 50, Appendix I, Sections II.A and

II.D. The NRC staff concludes that the LWMS will continue to perform its safety functions during EPU operation and that the system design is capable to withstand the effects of the EPU. The licensee's conclusion that existing equipment and procedures are unchanged to control releases using the LWMS appears adequate for EPU operation. Therefore, the NRC staff concludes that the licensee's assessment for the LWMS is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the LWMS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of liquid waste on the ability of the LWMS to control releases of radioactive materials. The NRC staff concludes that the LWMS will continue to meet their design functions following implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that the liquid waste management systems will continue to meet the requirements of 10 CFR 20.1302; GDC 60 and GDC 61; and 10 CFR Part 50, Appendix I, Sections II.A and II.D. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the LWMS.

2.5.5.3 Solid Waste Management Systems

Regulatory Evaluation

The review of the solid waste management systems (SWMS) focused on the effects that the proposed EPU may have on previous analyses and considerations related to the design objectives in terms of expected volumes of waste to be processed and handled, the wet and dry types of waste to be processed, the activity and expected radionuclide distribution contained in the waste, equipment design capacities, and the principal parameters employed in the design of the SWMS. The regulatory acceptance criteria for the SWMS are based on:
(1) 10 CFR 20.1302, "Compliance with dose limits for individual members of the public," insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC 60, "Control of releases of radioactive materials to the environment," insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) GDC 63, "Monitoring fuel and waste storage," insofar as it requires that systems be provided in waste handling areas to detect conditions that may result in excessive radiation levels; (4) GDC 64, "Monitoring radioactivity releases," insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs, and postulated accidents; and (5) 10 CFR 71, "Packaging and transportation of radioactive material," which provides the requirements for radioactive material packaging.

Technical Evaluation

The licensee used Section 8.1 of the CLTR (Reference 55) to address the effect of proposed EPU on the SWMS. The licensee described in the EPU LAR that the waste streams for the SWMS are (1) dry active waste, (2) spent ion exchange resin and filter sludge, and (3) filter sludge. The licensee stated that the EPU does not affect dry active waste so the volume and mix of dry active waste is unchanged. The effect of EPU on the SWMS is primarily a result of the increased load on the RWCU and condensate demineralizers. The increased demineralizer loads are expected to increase the volumes of spent ion exchange resin and filter sludge.

The NRC staff reviewed the licensee's assessment of the SWMS for EPU operation according to 10 CFR 20.1302, GDC 60, GDC 63, and GDC 64, and 10 CFR Part 71. The NRC staff noted that no design modifications are being made to the SWMS and that the system should continue to perform its design function under EPU conditions and within the regulatory requirements. The NRC staff concludes that the licensee's assessment of the SWMS is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the SWMS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of solid waste on the ability of the SWMS to process the waste. The NRC staff concludes that the SWMS will continue to meet its design functions following implementation of the proposed EPU.

The NRC staff further concludes that the licensee has demonstrated that the SWMS will continue to meet the requirements of 10 CFR 20.1302, GDC 60, GDC 63, and GDC 64, and 10 CFR Part 71. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the SWMS.

2.5.6 Additional Considerations

2.5.6.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

Regulatory Evaluation

Nuclear power plants are required to have redundant on-site emergency power supplies of sufficient capacity to perform their safety functions (e.g., power diesel engine-driven generator sets), assuming a single failure. The review focused on increases in emergency diesel generator electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function. The regulatory acceptance criteria for the emergency diesel engine fuel oil storage and transfer system are based on: (1) GDC 4, "Environmental and dynamic effects design bases," insofar as it requires that SSCs important to safety be protected against dynamic effects, including missiles, pipe whip, and jet-impingement forces associated with pipe breaks; (2) GDC 5, "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 (3) GDC 17, "Electric power systems," insofar as it requires on-site power supplies to have sufficient independence and redundancy to perform their safety functions, assuming a single failure.

Technical Evaluation

The licensee evaluated emergency diesel engine fuel oil storage and transfer for EPU operation for emergency loads and mission time. The licensee stated that the existing system equipment is sufficient to handle the emergency loads and that the mission time will remain unchanged for

EPU operation. In addition, the licensee indicated that no increase in flow or pressure is required of any AC-powered ECCS equipment for EPU operation and that the amount of power required to perform safety-related functions (pump and valve loads) is not increased with EPU.

The licensee concluded that the emergency diesel engine fuel oil storage and transfer system will continue to have sufficient capacity to support all required loads to achieve and maintain safe shutdown conditions and to operate the ECCS equipment following postulated accidents and transients.

The NRC staff has reviewed the licensee's assessment of the emergency diesel engine fuel oil storage and transfer system according to GDC 4, GDC 5, and GDC 17 and concludes that the system has the capability to perform its safety functions for EPU operation. No changes are being made to the emergency diesel engine fuel oil storage and transfer system and the regulatory requirements will continue to be met for EPU. Therefore, the NRC staff concludes that the licensee assessment of the emergency diesel engine fuel oil storage and transfer system is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the amount of required fuel oil for the emergency diesel generators and concludes that the licensee has adequately accounted for the effects of the increased electrical demand on fuel oil consumption. The NRC staff concludes that the fuel oil storage and transfer system will continue to provide an adequate amount of fuel oil to allow the diesel generators to meet the onsite power requirements of GDC 4, GDC 5, and GDC 17. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the fuel oil storage and transfer system.

2.5.6.2 Light Load Handling System (Related to Refueling)

Regulatory Evaluation

The light load handling system (LLHS) includes components and equipment used in handling new fuel at the receiving station and the loading of spent fuel into shipping casks. The review covered the avoidance of criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures. The review focused on the effects of the new fuel on system performance and related analyses. The regulatory acceptance criteria for the LLHS are based on: (1) GDC 61, "Fuel storage and handling and radioactivity control," insofar as it requires systems containing radioactivity be designed with appropriate confinement and with suitable shielding for radiation protection; and (2) GDC 62, "Prevention of criticality in fuel storage and handling," insofar as it requires that criticality be prevented.

Technical Evaluation

The licensee used Section 6.8 of the CLTR (Reference 55) to address the effect of the proposed EPU on GGNS plant systems that are not significantly affected. The LLHS includes components and equipment used for handling new fuel at the receiving station and for loading spent fuel into shipping casks. The licensee indicated that the LLHS will not be changed for

EPU operation and no new fuel designs are being introduced in conjunction with the proposed EPU. The licensee stated that the current design capability of the LLHS will continue to meet the required regulations for radioactivity releases and prevention of criticality accidents for EPU operation. The NRC staff has reviewed the licensee's assessment according to GDC 61 and GDC 62 and concludes that the licensee's assessment is acceptable since no changes are being made to the LLHS and the system was assessed to have the design capability to continue to perform its safety function under EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the new fuel on the ability of the LLHS to avoid criticality accidents and concludes that the licensee has adequately incorporated the effects of the new fuel in the analyses. Based on the above, the NRC staff further concludes that the LLHS will continue to meet the requirements of GDC 61 and GDC 62 for radioactivity releases and prevention of criticality accidents. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the LLHS.

2.6 Containment Review Considerations

2.6.1 Primary Containment Functional Design

Regulatory Evaluation

The containment encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. The NRC staff's review of the primary containment functional design covered (1) the temperature and pressure conditions in the drywell and wetwell that would result from a spectrum of postulated LOCAs, (2) suppression pool dynamic effects during a LOCA or following the actuation of one or more reactor coolant system (RCS), SRVs, (3) the consequences of a LOCA occurring within the containment (wetwell), (4) the capability of the containment to withstand the effects of steam bypassing the suppression pool, (5) the suppression pool temperature limit during RCS SRV operation, (6) the analytical models used for containment analysis, and (7) the differential pressure between drywell and containment for a spectrum of LOCAs. The NRC's acceptance criteria for the primary containment functional design are based on (1) 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 and that SSCs be protected against dynamic effects, (2) GDC 16, "Containment design," insofar as it requires that reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment, (3) GDC 50, "Containment design basis," insofar as it requires that the containment and its associated heat removal systems be designed so that the containment structure can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated temperature and pressure conditions resulting from any LOCA, (4) GDC 13, "Instrumentation and control," insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation and for accident conditions, as appropriate, to assure adequate safety, and (5) GDC 64, "Monitoring radioactivity releases," insofar as it requires that means be provided to monitor the reactor containment atmosphere for radioactivity that may be released from normal operations and from postulated accidents. SRP Section 6.2.1.1.C, "Pressure-Suppression Type BWR Containments" (Reference 62), contains specific review criteria for BWR containments.

Technical Evaluation

The GGNS primary containment is a Mark III type containment which consists of a reinforced concrete right circular cylinder with a hemispherical domed roof and a flat base slab. The containment design includes a drywell, a wetwell and containment regions. The major internal structures inside the containment include reactor shield wall, drywell, suppression pool weir wall, reactor support structure, miscellaneous platforms, upper containment pool, refueling floor, equipment rooms, process pipe tunnel, and support systems for the reactor recirculation pumps. The reactor shield wall is an open-ended cylindrical shell placed around the reactor vessel. The drywell is a cylindrical reinforced concrete structure which surrounds the reactor vessel and its support structure. The lower portion of the drywell wall is submerged in the suppression pool. Three rows of circular vents, 45 vents per row, penetrate the drywell wall below the normal level of the suppression pool. The wetwell which includes the suppression pool is considered to be a portion of the containment. The suppression pool weir wall located inside the drywell acts as the inner boundary of the suppression pool. It is constructed of reinforced concrete and extends from the outer edge of the drywell sump floor. The weir wall is lined with stainless steel plate on the suppression pool side. The suppression pool area of the containment liner is fabricated out of stainless steel.

The wetwell-to-drywell vacuum relief system consists of two vacuum breakers which equalize the pressure between the containment and the drywell to prevent a backflow of water from the suppression pool into the vent system.

The proposal to operate at EPU conditions requires that safety analyses for those DBAs whose results depend on power level be recalculated at the higher power level. The containment design basis is primarily established based on the LOCA and the actuation of the reactor vessel SRVs and their discharge into the suppression pool. The reactor vessel steam dome pressure remains constant at its pre-EPU value and, therefore, the EPU is regarded as a constant pressure power uprate (CPPU).

The GGNS UFSAR provides the results of the short-term and long-term containment analyses. The short-term analysis is directed primarily at determining the drywell pressure, drywell vapor temperature, and containment pressure response during the initial blowdown of the reactor vessel inventory to the drywell following a design basis LOCA. The long-term analysis is directed primarily at the suppression pool temperature, and containment pressure and temperatures responses considering the decay heat addition to the suppression pool. The effect of power on the events yielding the limiting containment pressure and temperature response is described below.

Short-Term LOCA Analysis for Pressure and Temperature Response

The short-term analysis for the pressure response covers the initial blowdown of the reactor vessel fluid to the drywell following a limiting DBA LOCA inside the drywell. The limiting DBA LOCA assumes a large double-ended guillotine recirculation suction line break (RSLB) or MSLB

(MSLB) inside the drywell. The licensee used analytical methods approved for EPUs. The decay heat model used is American Nuclear Society (ANS) Standard ANS-5-1971 plus 20 percent. For the RSLB, the licensee used the LAMB computer code (Reference 134) for the short-term mass and energy release input, and the M3CPT computer code (References 135 and 136) for the containment response. For the MSLB, the licensee used M3CPT code for mass and energy release as well as for the containment pressure and temperature response. The power uprate methods approved by the NRC permit the use of either the M3CPT computer code or the LAMB computer code to calculate the mass and energy release from the postulated pipe break inside the drywell.

The licensee performed the analysis assuming the reactor to be operating at 2 percent above the EPU reactor thermal power (RTP) to include instrument uncertainty effects.

In an NRC staff RAI dated March 1, 2011 (Reference 137), the licensee was requested to list and justify the differences of inputs between the CLB and EPU short-term analyses. In its response dated March 31, 2011 (Reference 12), the licensee listed three differences which are (a) the initial drywell and wetwell pressure increased from 0.0 psig to 1.5 psig, (b) initial drywell temperature decreased from 135 °F to 100 °F, and (c) initial wetwell temperature increased from 95 °F to 100 °F. The licensee stated that these changes in inputs are conservative relative to the CLB short-term analysis, because a higher initial drywell and wetwell pressure and a lower initial drywell temperature results in a larger mass of non-condensable gas which would predict a higher peak pressure in the drywell.

In an NRC staff RAI dated May 10, 2011 (Reference 138), the licensee was requested to provide reasons for using the initial drywell pressure of 1.5 psig instead of the scram setpoint drywell pressure of 2.5 psig or the maximum drywell pressure of 3.5 psig. In the same RAI, the licensee was requested to provide the value of relative humidity used in the analysis and justify if higher than the conservative value (minimum value for maximizing the mass of non-condensable gases) of 20 percent was used. In its response dated June 8, 2011 (Reference 18), the licensee stated that GGNS TS 3.6.1.4 requires that the differential pressure between the containment and secondary containment be no more than 1.0 psid. Since the secondary containment is maintained at a partial vacuum relative to the surrounding atmosphere during normal operation, the pressure in the containment during normal operation will not be much above atmospheric pressure. However, for the analysis a bounding normal operating pressure in the wetwell of 1.50 psig was assumed. The licensee further stated that GGNS does not require and does not typically operate with a significant differential pressure between the drywell and wetwell airspaces. Therefore, the analysis was performed with an initial drywell pressure same as the initial wetwell pressure. Regarding relative humidity, the licensee stated that initial drywell relative humidity assumed in the analysis was the minimum operating value of 20 percent, which is conservative since it results in larger mass of non-condensable gas.

In an RAI, the licensee was requested to provide the reasons for differences in the model for the MSLB area in the EPU analysis from the CLB break area model given in UFSAR Figure 6.2-9, and to explain the methodology used for calculating these flow areas as a function of time. In its response dated June 8, 2011 (Reference 18), the licensee provided the following reasons for the differences: (a) the EPU analysis uses the flow limiter area of 0.8862 square-feet per the as-built drawing, compared to 1.037 square-feet used in the CLB which was based on preliminary design information, (b) the EPU analysis uses a MSL area of 3.538 square-feet per the as-built drawing, same as the reactor nozzle safe-end area, compared to the MSL area of 3.449 square-feet used in the CLB which was based on preliminary design information, and (c) the EPU analysis applies a flow multiplier of 0.75 to the break area on the reactor side as well as to the flow limiter side during the time the flow from the break is experiencing a pressure wave that travels from the break location back to the source, compared to the CLB in which this multiplier was only applied to the break area on the reactor side. The explanation of the flow multiplier is given in Section B.4 of Appendix B in Reference 86. The licensee also corrected the time step "0.0110394 seconds" given in response to RAI 1.d dated March 31, 2011 (Reference 12), to "0.110394 seconds" in response to an RAI dated June 8, 2011 (Reference 18). The NRC staff concludes that the revised break area is acceptable because it is based on the as-built flow limiter and reactor nozzle safe-end drawings compared to the CLB break area which is based on preliminary design information.

Consistent with the CLB, the licensee stated that the most limiting values of short-term drywell pressure response under EPU conditions were obtained for the main steam line break (MSLB) inside the drywell. The licensee's calculated value of this parameter for an MSLB under EPU conditions is 27.0 psig which is below the drywell design pressure of 30 psig. Since this pressure does not act on any portion of the wetwell or the containment, therefore it is not considered as containment peak pressure. PUSAR Figure 2.6-4 shows the drywell pressure response, wetwell pressure response and the containment pressure response.

In an NRC staff RAI, the licensee was requested to discuss the reasons for the three (3) pressure peaks within the first five (5) seconds of the main MSLB LOCA analyses pressure response. In its response (Reference 21), the licensee provided an explanation regarding the three (3) peaks. The first two (2) peaks are related to the clearing of three (3) rows of vents, and the third peak is attributed to the pressurization of drywell following that of wetwell due to the flow resistance offered by the hydraulic control unit (HCU) floor between the wetwell air volume and the containment air volume above the HCU floor and subsequent pressure equalization between these volumes. This behavior is typical of Mark III containments, as described in Reference 136. The NRC staff concludes that the licensee's explanation regarding the three (3) peaks in the drywell pressure response acceptable.

The evaluation of peak drywell temperature response is given in Section 2.6.3.1 of this SE.

Consistent with the CLB, the licensee stated that the most limiting value of the short-term peak containment pressure for the EPU was obtained for the MSLB inside the drywell. The licensee's calculated value for an MSLB under EPU conditions is 14.8 psig which is below the containment design pressure (CDP) of 15 psig.

The NRC staff concludes that the revised limiting values of peak drywell pressure and temperature and peak containment pressure under EPU conditions are acceptable because the licensee used conservative assumptions and inputs for the analysis, and the results obtained are bounded by their respective design limits.

Table 2.6-1 of the PUSAR (Reference 57) and Reference 18, present the results obtained from the short-term analyses for EPU conditions. In this table the licensee showed the effects on important parameters that result from the power uprate and those that result from the change in analysis assumptions. In an NRC staff RAI, the NRC staff requested the licensee to explain why the results of containment analysis for DBA LOCA at CLTP (column 2 of PUSAR Table 2.6-1) differ from the DBA LOCA results at CLTP with the EPU model (column 3 of PUSAR Table 2.6-1). The licensee stated that the results differ because of changes in analysis inputs stated above and refinements in methodology since the time of the analysis of record (AOR). Table 2.6.1-1 below presents the licensee's short-term analysis results for drywell and containment pressure response extracted from Table 2.6-1 of PUSAR and Reference 18.

Table 2.6.1-1. EPU Short-Term DBA-LOCA
Drywell and Containment Pressure Response Results

Parameter	Limiting Event	DBA LOCA CLTP from AOR	DBA LOCA CLTP- with EPU Model	EPU Analysis	Design Limit
Peak drywell Pressure (psig)	MSLB	22.0	26.6	26.7	30
Peak Containment Pressure (psig)	MSLB	Not reported	14.7	14.8	15
Peak drywell to containment differential pressure (psi)	(1) MSLB (2) RSLB	22.0 (1)	24.2 (2)	24.2 (2)	30

NRC Staff Confirmatory Analysis for Short Term Containment Pressure Response

The NRC staff performed confirmatory calculations for RSLB and MSLB events under EPU conditions and concludes that the results are in agreement with the licensee's results.

Long-Term LOCA and Alternate Shutdown Cooling Analysis for Suppression Pool Temperature, and Containment Pressure and Temperature Response

The licensee performed long-term containment analyses to determine the limiting values of peak suppression pool temperature and peak containment pressure and temperature by considering the long-term addition of decay heat to the suppression pool. The alternate shutdown cooling (ASDC) event and DBA LOCA which includes RSLB and MSLB were analyzed for EPU conditions. The licensee used ANSI/ANS 5.1-1979 decay heat model with 2 standard deviation (2σ) uncertainty added which is same as in current UFSAR analysis The licensee incorporated the guidance of GE Service Information Letter (SIL) 636, Revision 1 (Reference 139), which recommends additional decay heat by accounting for additional actinides and activation products. This analysis was performed using analytic methods approved for EPU. The SHEX computer code is used for the analysis of the peak suppression pool temperature. The licensee stated that the key models in SHEX are based on models described in Reference 136. The NRC has accepted this computer code for previous power uprate applications.

The licensee performed the analysis assuming the reactor to be operating at 2 percent above the EPU RTP which included the effects of instrument uncertainty.

Consistent with the CLB, the licensee stated that most limiting values of long-term peak containment pressure for EPU was obtained for the MSLB inside the drywell. The licensee's calculated value of this parameter for MSLB under EPU conditions is 11.9 psig which is below the CDP of 15 psig.

The licensee stated that the most limiting value of long-term peak bulk suppression pool temperature for EPU was obtained for the alternate shutdown cooling (ASDC) event. The licensee's calculated value of this parameter for the ASDC event under EPU conditions is 198 °F which is higher than its current design temperature of 185 °F. The licensee has therefore increased the suppression pool design temperature to 210 °F for EPU implementation. The evaluation of the impact of the increased temperature limit on the containment structural integrity is given below.

The licensee stated that the most limiting value of long-term peak containment gas space temperature for EPU was obtained for the ASDC event. The licensee's calculated value of this parameter for the ASDC event under EPU conditions is 154 °F which is less than the containment design temperature of 185 °F.

In its June 8, 2011, response to an NRC staff RAI, the licensee was requested to (a) describe the limiting ASDC analysis for which the results are documented in PUSAR Table 2.6-1, (b) provide a comparison of the EPU sequence of events with the CLB sequence of events documented in UFSAR Table 15.2-13 and justify differences, and (c) provide a comparison of the EPU input parameters for the evaluation of ASDC with the CLB input parameters documented in UFSAR Table 15.2-14 and justify differences. In its response, the licensee described the ASDC analysis, including sequence of events, which resulted in the most limiting long-term peak suppression pool temperature and most limiting long-term peak containment gas space temperature. The licensee also described the conservatisms in the analysis and a comparison with the CLB analysis including justification of differences. The NRC staff reviewed the RAI response and considers it is acceptable because, as stated, acceptable methods and conservative assumptions were used and the differences between the CLB and the EPU analysis inputs were adequately justified.

Table 2.6-1 of the PUSAR presents the results obtained from these analyses for EPU conditions. These results extracted from PUSAR Table 2.6-1, and Figure 2.6-3 are provided in Table 2.6.1-2 below. In this table the licensee showed the effects on important parameters that result from the power uprate and those that result from the change in analysis assumptions. In an NRC staff RAI, the licensee was requested to explain why the results of containment analysis for DBA LOCA at CLTP (column 2 of PUSAR Table 2.6-1) differ from the DBA LOCA results at CLTP with the EPU model (column 3 of PUSAR Table 2.6-1). The licensee stated that the results differ because of changes in analysis inputs and refinements in methodology since the time of AOR. The particular input values that affect the analysis are (a) initial drywell and wetwell pressures were increased from 0.0 psig to 1.5 psig, (b) initial drywell temperature was decreased from 135 °F to 100 °F, and (c) initial suppression pool temperature was increased from 95 °F to 100 °F for long-term containment response analysis. The licensee also stated that the peak containment temperature is substantially decreased because the new methodology no longer forces thermal equilibrium in the containment to be applied as it was applied in the AOR. This assumption also decreases the long-term containment pressure. The

NRC staff concludes that the assumption of not forcing thermal equilibrium between the suppression and containment vapor space and using a mechanistic model for heat and mass transfer as realistic and is acceptable. The NRC staff concludes that the EPU long-term analysis is acceptable because the licensee used NRC's accepted computer code and method, and the inputs and assumptions other than the assumption of thermal equilibrium remain conservative.

P_a is the pressure at which containment leakage rate testing is performed as per the requirements of 10 CFR Part 50 Appendix J. It is defined in 10 CFR Part 50 Appendix J as the calculated peak containment internal pressure resulting from the design-basis LOCA. As per Table 2.6.1-2 below, the licensee reported the EPU peak containment internal pressure related to the design-basis LOCA as 11.9 psig. In an NRC staff RAI, the NRC staff requested the licensee to confirm that the short-term containment peak pressure of 14.8 psig (see Table 2.6.1-1 above) will be used as the revised 'P_a' for the 10 CFR 50 Appendix J integrated leak rate test (ILRT) pressure under EPU conditions, since this is the calculated peak containment pressure replacing the CLB 'P_a' of 11.5 psig. In its response dated June 8, 2011, the licensee provided the following reasons for using 'P_a' as 11.9 psig instead of 14.8 psig: (a) the short-term containment pressure reaches 14.8 psig and terminates in about six (6) seconds after the event, and does not represent containment bulk pressure because it occurs in a localized containment region, (b) as per Table 4, "LOCA Release Phases," of NRC Regulatory Guide (RG) 1.183, Revision 0, "Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," July 2000 (Reference 140), BWR core source terms do not begin to be released from the reactor vessel until 2 minutes after a LOCA. The only radioactivity released from the reactor during the first 6 seconds is associated with the reactor coolant. This source term is very small and is scrubbed by the suppression pool. Considering the primary containment function is to mitigate radioactivity leakage, the impact of any additional leakage rate associated with this early period would be negligible due to its low source term. The NRC staff concludes that the licensee has not justified the use of 11.9 psig as the revised value of P_a which meets the definition given in 10 CFR 50 Appendix J. The NRC staff also noted that the value of P_a is not given in the TS as required by its definition given in 10 CFR Appendix J Option B, Section II. During its review, the NRC staff informed the licensee that it had the following two issues related to the Appendix J containment test pressure:

(a) The NRC staff stated that assigning 11.9 psig (instead of 14.8 psig) as the revised value of P_a unacceptable because it is not consistent with the 10 CFR 50 Appendix J definition of the calculated peak containment pressure. The NRC staff concluded that wetwell is a significant volume of the containment and therefore the calculated peak containment internal pressure of 14.8 psig in the short-term analysis (as per Table 2.6.1-1 above) should be assigned to P_a after EPU implementation.

(b) In addition, the value of P_a should be included in the TS in order to meet its definition in 10 CFR 50 Appendix J, Option B, Section II, "*P_a (psig)* means the calculated peak containment internal pressure related to the design basis loss-of-coolant accident as specified in the Technical Specifications."

By letter dated September 9, 2011 (Reference 28), the licensee resolved the above issues by agreeing to (a) assign the short-term peak containment of 14.8 psig as the revised TS value of P_a, and (b) incorporate the value of P_a of 14.8 psig in Section 5.5.12 of the TS.

Table 2.6.1-2. EPU Long-Term LOCA and ASDC Containment Performance Results

Parameter	Event	DBA LOCA CLTP from AOR	DBA LOCA CLTP- with EPU Model	EPU Analysis	Design Limit
Peak Containment Pressure (psig)	MSLB (limiting)	11.5	11.3	11.9	15
Peak Bulk SP [suppression pool] Temperature (°F)	RSLB	181	184	189	210*
Peak Bulk SP Temperature (°F)	ASDC (limiting)	Not reported	191	198	210*
Peak Containment Temperature (°F)	RSLB	181	138	142	185
Peak Containment Temperature (°F)	ASDC (limiting)	Not reported	Not reported	154	185

*The licensee has increased the design limit for the bulk suppression pool temperature from the current design temperature of 185 °F to EPU design temperature of 210 °F. The NRC staff evaluation of the revised suppression pool temperature limit on containment structural integrity is given below.

NRC Staff Confirmatory Analysis for Long Term Response

The NRC staff performed confirmatory calculations for RSLB and MSLB events under EPU conditions and concluded the results were in agreement with the licensee's results.

Local Pool Temperature with SRV Discharge

NUREG-0783, "SP Temperature Limits for BWR Containments," November 1981 (Reference 141), specified local suppression pool temperature limits to ensure stable steam condensation without the imposition of significant loads on the containment. Subsequently, the BWROG submitted topical reports NEDO-30832, "Elimination of Limit on BWR SP Temperature for SRV Discharge with Quenchers," dated March 21, 1985 (Reference 142), and NEDO-31695, "BWR SP Temperature Technical Specification Limits," dated May 9, 1989 (Reference 143) for the NRC staff's review. These two reports provide a technical basis for the elimination of suppression pool local temperature limits, and were approved by the NRC staff in a safety evaluation report (SER) dated August 29, 1994 (Reference 144). The conclusion in the SER specifically stated that local suppression pool temperature limits could be eliminated for plants that meet the following criteria:

(1) The plant has SRV discharges directed to the suppression pool through a T- or X-quencher device previously approved by the NRC staff, and

(2) The plant emergency safety features pump inlets are located below the elevation of the SRV quenchers.

The licensee stated there are X-quenchers at SRV discharges and its emergency core cooling system (ECCS) suction strainers are located below these X-quenchers; therefore, a local pool temperature analysis is not required. The NRC staff agrees that the licensee's conclusion is acceptable because it meets the acceptance criteria in Reference 142.

Steam Bypass Capability

The licensee stated that the use of the CLB steam bypass effective area capability $A/\sqrt{K}$ = 0.9 ft^2 at EPU conditions resulted in a containment pressure that exceeded the CDP. The licensee performed revised steam bypass analysis to establish the maximum allowable effective steam bypass area with EPU conditions and determined that an effective steam bypass area of $A/\sqrt{K}$ = 0.8 ft^2 would maintain the peak calculated containment pressure within the design limit with EPU conditions. GGNS UFSAR Sections 6.2.1.1.5.4 and 6.2.1.1.5.5 provide results and assumptions of CLB (CLB) steam bypass capability analysis 'without sprays and heat sinks' and 'with sprays and heat sinks' respectively for small reactor system breaks. In an NRC staff RAI, the licensee was requested to provide a table comparing the assumptions and results of the CLB and the EPU analysis including justification of differences in assumptions used in the EPU drywell bypass analysis. In its response dated March 31, 2011 (Reference 12), the licensee listed four differences between the CLB and EPU analysis and justified the differences which are acceptable to the NRC staff. The GGNS TS includes SR 3.6.5.1.1 to verify the bypass leakage is within the acceptable limits.

Hydrodynamic LOCA Loads

A part of the containment design basis is the acceptable response of the containment to hydrodynamic loads associated with the discharge of reactor fluid and drywell non-condensable into the suppression pool following a LOCA.

The licensee stated that the LOCA containment dynamic loads analysis is based on the RSLB and compliance with generic criteria developed through testing programs. As part of EPU evaluation, the licensee must ensure that these analyses remain bounding for operation at EPU conditions. This licensee performed this analysis by the pressure and temperature calculations for the short-term DBA LOCA assuming a RSLB. The key parameters are the transient drywell and wetwell pressure, vent flow rates, and the suppression pool temperature. The licensee considered LOCA-induced loads which include pool swell loads, CO loads, and chugging loads. In an NRC staff RAI, the licensee was requested to describe the analysis and its results that determined the effect of vent clearing pressure, CO pressure, and chugging pressure on the weir wall. In its response dated March 31, 2011 (Reference 12), the licensee described a qualitative evaluation of the effect of the vent clearing, CO, and chugging pressure on the weir wall. Comparison of the inputs for the most limiting EPU containment analysis to those assumed for the original containment analysis used for the design bases hydrodynamic loads confirmed that the EPU containment response results are bounded by those used to define the original design loads. The EPU containment response results being within the range of containment conditions used to define the dynamic loads demonstrates that the dynamic design loads on the weir wall are not affected by the power uprate. From the results of the EPU pool swell evaluations, the licensee confirmed that the current pool swell load definitions remain bounding. The licensee stated that the EPU short-term DBA LOCA analysis for the RSLB is the bounding analysis for CO, and the resulting loads are bounded by the generic Mark III CO load definition. Also the licensee confirmed that the containment response conditions for EPU are within the range of test conditions used to define CO loads for the plant. Regarding the chugging loads, the licensee stated that the containment response conditions for EPU are within the conditions used to define the chugging loads. The licensee confirmed that the EPU long-term analysis was performed for several break sizes and the resulting chugging loads were bounded by the current chugging loads. The NRC staff concludes that the licensee's evaluation is acceptable because the licensee has confirmed that the EPU containment loads are bounded by the current load definitions.

Hydrodynamic Safety/Relief Valve Actuation Loads

A part of the containment design basis is the acceptable response of the containment to hydrodynamic loads associated with the discharge of reactor steam into the suppression pool following a SRV actuation. The SRV loads evaluated for the EPU are SRV discharge lines loads, suppression pool boundary loads, and loads on submerged structures in the suppression pool. The loads are evaluated for initial and subsequent SRV actuations.

The licensee evaluated the containment loads due to SRV initial actuation. The parameter affecting the SRV loads is the SRV opening set-points. The licensee stated there are no changes in the SRV opening set-points, no changes in the SRV discharge lines air and water volumes, and there are no changes in the suppression pool submerged structures under EPU conditions. Therefore for initial actuation the EPU does not affect the SRV loads. The NRC staff concludes that the licensee's evaluation is acceptable because the proposed EPU is a CPPU which does not change the reactor operating pressure.

For subsequent actuation, the licensee stated that the load definition assumes only one SRV opens, for which the low-low set (LLS) SRV setpoint logic has been implemented. The licensee performed an analysis that demonstrated the LLS logic successfully prevented multiple-valve actuation and the time between successive actuations was long enough that the water inside the SRV discharge line returns to its pre-actuation or a lower than pre-actuation water level. Therefore, subsequent SRV actuation under EPU conditions will not affect the current SRV containment load definition. In an RAI, the licensee was requested to describe the analyses which demonstrated that the LLS SRV setpoint logic successfully prevented subsequent actuations of multiple valves and that the time between successive actuations of the SRV is long enough that the water in the discharge line returns to its pre-actuation or lower than pre-actuation level. In its response dated March 31, 2011 (Reference 12), the licensee stated that the analysis was performed using the ODYN code and May-Witt decay heat model which is more conservative than the ANSI 5.1-1979 plus 2 sigma model. This analysis demonstrated that one SRV's capacity to reduce pressure prevented opening of the other LLS SRVs. The results show that the time between SRV closure and reopening for a postulated transient is 32 seconds. The licensee also stated that SRV test results show that the water level in the SRV discharge line would return to its pre-actuation level in approximately 5 seconds. Based on this time difference, it is expected that subsequent actuation of the same SRV would not occur prior to water level in the discharge line reaching its pre-actuation level.

The NRC staff concludes that the licensee has provided valid reasons and performed an analysis supporting the conclusion that the initial and subsequent SRV actuations under EPU conditions will not affect the current SRV containment load definition and is, therefore, acceptable.

Impact of Revised Suppression Pool Temperature Limit on Containment Structural Integrity

Section 2.6.1.1 of the PUSAR details the assessment performed by the licensee regarding the pressure and temperature response of the containment structure as a result of EPU implementation. As stated in the PUSAR and Section 4.1 of NEDC-33004P-A (Reference 55), EPU implementation results in higher decay heat levels following a DBA. Subsequently, to support EPU implementation, the licensee indicated in the PUSAR that the design limit of the bulk suppression pool temperature would be raised from 185 °F to 210 °F as a result of the higher decay heat coupled with EPU implementation.

The NRC staff issued one RAI (Reference 138) to the licensee requesting supplemental information concerning the structural evaluations which had been performed to support the increase in the bulk suppression pool design temperature. In its response (Reference 18) to the NRC staff's RAI, the licensee stated that the increased suppression pool temperature was incorporated into the revised structural evaluations. These evaluations were performed to determine whether the containment structure would continue to satisfy the design-basis acceptance criteria used to determine its structural adequacy following EPU implementation. Section 3.8.1 of the UFSAR provides detailed information regarding the design bases of the containment structure, including the methodology used in the original structural analysis of the containment and the loading combinations and corresponding structural acceptance criteria used in the design of the structure.

In its RAI response dated March 31, 2011 (Reference 12), the licensee identified three loading combinations (termed LC1, LC2, and LC3) which would be adversely affected by the increase in the bulk suppression pool temperature. Each of these loading combinations contains loads which are dependent on the temperature of the suppression pool following a DBA. The licensee stated that the second and third loading combinations had been previously evaluated, and deemed adequate, for abnormal thermal loads using suppression pool temperatures of 215 °F and 226 °F, respectively, thus negating the need to re-evaluate these loading combinations for an suppression pool temperature of 210 °F. However, the licensee stated that LC1 was re-evaluated for a temperature of 215 °F in support of EPU implementation. By combining thermal loads resulting from this suppression pool temperature with the mechanical loads, the licensee determined that the containment structure continued to satisfy the applicable acceptance criteria with the higher thermal loads.

The NRC staff reviewed the licensee's assessment of the effects of EPU implementation on the structural integrity of the containment structure and concludes that the assessment is sufficient and acceptable, based on the following rationale. The NRC staff concludes that the licensee's evaluation is acceptable based on the fact that the methodology utilized in the evaluation is consistent with the guidance provided in Section 4.1 of the NEDC-33004P-A (Reference 55). This portion of NEDC-33004P-A directs the licensee to utilize the methodologies provided in Appendix G of NEDC-32424P-A (Reference 58). Appendix G of NEDC-32424P-A states that the licensee should ensure that increased loads on the containment structure are evaluated to determine whether the stress limits applicable to the containment structure will continue to be satisfied following EPU implementation. As such, the NRC staff's primary review criteria relies on ensuring that the containment structure, as designed and constructed, will continue to maintain its structural integrity following EPU implementation, given that the licensee is making no modifications to the containment structure which would affect its load bearing capacity. Subsequently, the current load bearing capacity of the containment structure must be able to withstand any load increases caused by EPU implementation and continue to satisfy the structural acceptance criteria which the containment was designed against.

Containment Isolation

The licensee evaluated the containment isolation portions of the systems penetrating the primary containment and determined that EPU does not affect the containment isolation equipment and the capability to isolate the primary containment during normal or accident conditions.

Generic Letter 96-06

The licensee reviewed its current responses to NRC Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity during Design-Basis Accident Conditions," dated September 30, 1996 (Reference 145), and stated that the existing responses to this generic letter remain valid for EPU.

Conclusion

The NRC staff has reviewed the licensee's assessment of the containment temperature and pressure transients and concludes that the licensee has adequately accounted for the increase of mass and energy resulting 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 containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and the containment and associated systems will continue to meet the requirements of GDCs 4, 13, 16, 50, and 64 following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to primary containment functional design.

The NRC staff concludes that the licensee's assessment of containment structural integrity due to the revised suppression pool design temperature is acceptable based on the fact that the licensee provided explicit details regarding the effects of increasing the suppression pool design temperature on the design-basis loading combinations used in evaluating the structural adequacy of the containment. The NRC staff notes that one of the loading combinations affected by the increased suppression pool design temperature had not been previously evaluated for suppression pool design temperatures as high as those being proposed under EPU conditions (i.e., 210 ^{o}F). However, for this loading combination, the licensee demonstrated that thermal loads resulting from the increased suppression pool design temperature, in combination with the mechanical loads, will continue to satisfy the design-basis acceptance criteria for the containment structure. Therefore, based on the licensee's demonstration that the loading combinations affected by a higher suppression pool design temperature will continue to satisfy the applicable acceptance criteria, the NRC staff concludes that there is reasonable assurance that the containment structure will maintain its structural integrity under design-basis loading conditions following EPU implementation.

2.6.2 Subcompartment Analyses

Regulatory Evaluation

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The NRC staff's review of subcompartment analyses covered the determination of the differential pressure values for containment subcompartments and comparison with the design values to ensure that margin exists. The NRC staff's review focused on the effects of the increase in mass and energy release into the containment caused by operation at EPU conditions and the resulting increase in pressurization. The NRC's acceptance criteria for subcompartment analyses are based on (1) 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, and that such SSCs be protected against dynamic effects, and (2) GDC 50, "Containment design basis" insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure resulting from the calculated pressure differential conditions across the walls of the subcompartments. SRP Section 6.2.1.2, "Subcompartment Analysis" (Reference 62), contains specific review criteria.

Technical Evaluation

The two subcompartments to be evaluated for HELBs are the reactor BSW annulus and the region between the reactor head and the drywell head, regarded as the drywell head region.

The walls of these subcompartments are required to withstand with sufficient margin the differential pressure developed due to HELBs in these regions. Also the containment SSCs important to safety should continue to be protected from the dynamic effects resulting from HELBs in these subcompartments.

Biological Shield Wall Annulus Pressurization Analysis

The pressurization of the BSW annulus is attributed to three HELBs that would result in a differential pressure load across the BSW. The breaks are the recirculation suction line break (RSLB), recirculation discharge line break (RDLB) and feedwater line break (FWLB). The licensee stated that a pipe break in this region results in a combination of four dynamic loads, referred to as annulus pressurization (AP) loads. These four dynamic loads consist of: (1) the asymmetric pressurization of the annular area between the BSW and RPV, (2) the jet reaction resulting from the break flow through the reactor vessel nozzle, (3) the jet impingement on the vessel of the break flow from the broken pipe, and (4) the effect of load absorbed by the PWR. These loads are a function of the break size, location, fluid thermal-hydraulic conditions, and the annular vent area to the rest of the drywell.

The licensee stated that the original licensing basis mass and energy release analysis was based on the methodology documented in GE document NEDO-24548, "Annulus Pressurization Load Adequacy Evaluation," January 1979 (Reference 146). The licensee also stated that NEDO-24548 mass and energy release methodology was judged to be potentially non-conservative as the method could potentially result in artificial shifts of the pressure response frequency content." In an NRC staff RAI, the licensee was requested to describe the issues that make the NEDO-24548 methodology non-conservative. In its response dated March 31, 2011 (Reference 12), the licensee stated that the NEDO-24548 methodology has not been shown to be non-conservative in any analysis performed so far. However, it was identified that the simple methods such as NEDO-24548 could potentially result in shifts of the frequency content of the annulus pressurization response away from the resonant frequencies of the structures and components which could underestimate the dynamic amplification of the pressurization loads. The licensee also outlined some inconsistencies and an error in the original licensing basis and stated that these have been addressed in the GGNS corrective action program and corrected in the EPU evaluations.

The licensee performed the EPU break mass and energy (M&E) release calculations for the BSW annulus pressurization analysis using the TRACG methodology. The licensee stated that the application of this methodology is consistent with the application of thermal-hydraulic codes such as RELAP for the evaluation of M&E release. The methodology includes a detailed reactor vessel model and includes line losses, fluid inertia, and considers flashing that occurs in the ruptured lines. The licensee also stated that TRACG predicts more realistic M&E release for off-rated reactor conditions as compared to the current NEDO-24548 (Reference 14) hand calculation method which ignores fluid inertia, line losses and flashing in the ruptured lines. The NRC staff has approved TRACG for application to the economic simplified boiling water reactor (ESBWR) in general (see GE Hitachi Nuclear Energy Americas LLC, NEDC-33083P-A, "TRACG Application for ESBWR," October 2005 (Reference 147)). Responses to several RAIs related to application of TRACG to ESBWR subcompartment analysis were provided by General Electric Hitachi in NEDC-33440P, "General Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," February 1999 (Reference 148). The NRC staff's confirmatory analysis for ESBWR BSW pressurization using NRC's computer code TRACE is given in "ESBWR Shield Wall Pressurization Confirmatory Analysis," July 2009 (Reference 149). Based on the information in References 147, 148, and 149, the NRC staff accepts the use of TRACG for GGNS BSW annulus pressurization analysis. The licensee's TRACG model for the GGNS included a reactor vessel model with breaks at the reactor nozzle safe-ends to pipe welds for the recirculation suction, recirculation discharge and feedwater nozzles. The licensee stated that a finer nodal mesh consisting of 384 nodes for the BSW annulus was used in TRACG analysis as compared to the original licensing basis analysis mesh which consisted of 25 nodes. The licensee used the same BSW annulus nodalization scheme for all breaks analyzed. This nodalization scheme was based on (a) uniform angular sectors, (b) cell height to width aspect ratio of approximately one (1), and (c) modeling of all blockages at the cell boundaries. The licensee stated that maintaining the aspect ratio of the cells close to one (1) ensures that the nodalization does not distort the acoustic wave propagation and accurately captures the pressure waves in the annulus. The same initial conditions were assumed as in the CLB analysis. The break flow rates were calculated using the Moody homogeneous equilibrium model (HEM). The licensee stated that because of higher accuracy in thermal hydraulic model of the reactor vessel along with finer BSW annulus nodes, the EPU TRACG methodology provides better estimates of the transient forces and moments on the SSCs and the attached piping. The NRC staff concludes that the licensee's BSW annulus pressurization analysis is acceptable because the licensee used the NRC staff accepted TRACG methodology (including nodalization) for similar analysis for the ESBWR.

Using the results of BSW annulus pressurization analysis, the licensee calculated the jet reaction, jet impingement loads following ANSI/ANS-58.2-1988 and the guidelines provided in paragraphs (2) and (3) of Section III.2.C of SRP Section 3.6.2, "Determination of Rupture Locations and Dynamic Effects Associated with the Postulated Rupture of Piping" (Reference 62). The AP, jet impingement, jet reaction, and PWR loads are input for structural analysis. The evaluation of these load calculation methods and structural analysis is provided in Section 2.2 of this SE.

Drywell Head Region Subcompartment Analysis

The pressurization of the drywell head subcompartment is attributed to either two HELBs that would result in a differential pressure load across the drywell head refueling bulkhead plate. The high energy lines are the RPV head spray line and the MSL. The licensee stated that the CLB drywell head region differential pressure analysis is unaffected by the EPU because the steam dome pressure does not change. The NRC staff concludes the licensee's evaluation is acceptable because it considers the drywell head refueling bulkhead plate differential pressure unaffected by HELB under EPU conditions.

Conclusion

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization. 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 as the result of pressure difference across the walls following implementation of the proposed EPU. Based on the above, the NRC staff concludes that the plant will continue to meet GDC 4 and 50 for the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to subcompartment analyses.

2.6.3 Mass and Energy Release

2.6.3.1 Mass and Energy Release Analysis for Postulated Loss of Coolant

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, "Containment design basis," 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) Appendix K, "ECCS Evaluation Models," to 10 CFR Part 50, insofar as it identifies sources of energy during a LOCA. SRP Section 6.2.1.3, "Mass and Energy Release Analysis for Postulated Loss-of-Coolant Accidents (LOCAs)" (Reference 62), contains specific review criteria.

Technical Evaluation

Drywell Temperature Response

In the CLB analysis the drywell design temperature 330 °F reported in UFSAR Section 6.2.1.1.3.3.5.4 was determined independent of the initial reactor power. The analysis that calculated a peak drywell temperature of 330 °F was based on the gas temperature caused by blowdown of steam into the drywell during a small break LOCA. The licensee stated that since the peak temperature was calculated independent of the reactor thermal power, therefore EPU has no effect on the peak drywell temperature. The NRC staff concludes that the licensee's evaluation acceptable.

Containment Temperature Response

The containment temperature response is affected by the higher decay heat due to increase in the reactor thermal power. Using the decay heat under EPU conditions for the DBA LOCA, the resulting containment temperature is evaluated in Section 2.6.1 in this SE.

Short-Term Containment Pressure Response

The assumption of same reactor pressure under EPU conditions as in the CLB does not affect the short-term mass and energy release inside the drywell for a DBA LOCA. The licensee stated that for EPU, the limiting short-term containment pressure response was obtained for the MSLB. The licensee performed this analysis at 102 percent EPU reactor power and decay heat per ANS 5.1-1971 plus 20 percent. The analysis covered the blowdown period during which the maximum drywell pressure, wetwell pressure, and the differential between the drywell and the wetwell occurred. Refer to Section 2.6.1 and Table 2.6.1-1 in this SE for the EPU short-term pressure response evaluation and results.

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 Appendix K to 10 CFR Part 50. Based on this, the NRC staff concludes that the mass and energy release analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to mass and energy release for a postulated LOCA.

2.6.4 Combustible Gas Control in Containment

Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment as the result of 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 the mitigation of any increases in hydrogen release.

The NRC's acceptance criteria for combustible gas control in containment are based on (1) 10 CFR 50.44, "Combustible gas control for nuclear power reactors," insofar as it requires that containments that do not rely upon an inerted atmosphere inside containment, to control combustible gases, must have the capability for controlling combustible gas generated from metal-water reaction, and must be able to establish and maintain safe shutdown and containment structural integrity with systems and components capable of performing their functions during and after exposure to the environmental conditions created by the burning of hydrogen. (2) 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, (3) GDC 41, "Containment atmosphere cleanup," insofar as it requires that systems be provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure that containment integrity is maintained, (4) GDC 42, "Inspection of containment atmosphere cleanup systems," insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic inspection, and (5) GDC 43, "Testing of containment atmosphere cleanup systems," insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic testing. SRP Section 6.2.5, "Combustible Gas Control in Containment" (Reference 62), contains specific review criteria.

Technical Evaluation

The NRC has revised 10 CFR 50.44, "Combustible gas control system for nuclear power reactors." The amended regulation eliminated the requirements for hydrogen recombiners and relaxed the requirements for hydrogen and oxygen monitoring in containment. The revised 10 CFR 50.44 no longer defines a design-basis LOCA hydrogen release, and eliminates requirements for hydrogen control systems to mitigate such a release. By letter dated June 16, 2004 (Reference 150), the NRC approved the GGNS Amendment No. 166 that removed the requirements for hydrogen recombiners. As per the UFSAR, the hydrogen ignition system is designed to periodically burn hydrogen that is released to the containment and drywell during a degraded core accident. This system is not affected by the EPU. Therefore, the EPU does not affect the design of hydrogen control system.

Conclusion

The NRC staff has reviewed the licensee's assessment related to combustible gas and concludes that the plant design is consistent with the requirements in 10 CFR 50.44 and 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," for systems required 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 at EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to combustible gas control in containment.

2.6.5 Containment Heat Removal

Regulatory Evaluation

Fan cooler systems, spray systems, and RHR systems are provided to remove heat from the containment atmosphere and from the water in the containment wetwell. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the net positive suction head (NPSH) available 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, "Containment heat removal," insofar as it requires that a containment heat removal system be provided and that its function shall be to rapidly reduce the containment pressure and temperature following a LOCA and maintain them at acceptably low levels. SRP Section 6.2.2, "Containment Heat Removal Systems" (Reference 62), as supplemented by NRC Regulatory Guide (RG) 1.82, Revision 3, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident," November 2003 (Reference 151), contains specific review criteria.

Technical Evaluation

The implementation of EPU will increase the reactor decay heat following the DBA-LOCA, ATWS, Station Blackout (SBO), and Appendix R events and therefore will increase the heat input to the suppression pool. The containment integrity evaluation under EPU conditions using the existing containment heat removal system is given in Section 2.6.1 of this report.

This increased heat input increases the peak suppression pool water temperature, which changes the available net positive suction head (NPSH) of the residual heat removal (RHR), low pressure core spray (LPCS), and high pressure core spray (HPCS) pumps. The licensee has increased the design limit for the bulk suppression pool temperature from the current value of 185 °F to 210 °F for EPU implementation.

Adequate NPSH margin (NPSH available (NPSHA) minus NPSH required (NPSHR)) is required during the post-LOCA, ATWS, SBO, and Appendix R fire events to assure operation of the ECCS pumps used for mitigation of these events.

The licensee calculated the NPSH margins for the ECCS pumps for the limiting conditions following a DBA LOCA at 102 percent EPU reactor power, decay heat as per ANS 5.1-1979 plus 2-sigma added for uncertainty, and assuming a single failure of one out of two RHR heat exchangers. The licensee calculated peak suppression pool bulk temperature to be 189 °F. The licensee stated that the calculated temperature is bounded by the ECCS NPSH pump limit of 194 °F for the DBA LOCA event. In an NRC staff RAI, the licensee was requested to provide an explanation of what is meant by "ECCS NPSH pump limit of 194 °F" as stated in PUSAR Section 2.6.5.1. In its response the licensee stated that since the EPU post-LOCA pool temperature exceeded the CLB temperature of 185 ºF, the ECCS pump NPSHA was evaluated at higher pool temperature of 194 ºF for debris-generating events like the LOCA which would provide sufficient NPSHA to the most limiting ECCS pump.

In an NRC staff RAI, the licensee was requested to refer to PUSAR Section 2.6.5.1, third paragraph and provide the limiting value of NPSHA at 189 °F and the limiting values of the required NPSH (including uncertainties) for the ECCS pumps during the EPU DBA-LOCA event. In its response dated March 31, 2011 (Reference 12), the licensee stated that while taking no credit for the containment accident pressure, Table 2.6.5-1 below provides the values of NPSHA for DBA-LOCA event at 189 °F and the NPSHR without uncertainties for ECCS pumps.

Table 2.6.5-1. NPSHA for DBA-LOCA and Non-LOCA Events and NPSHR Values for ECCS Pumps

Pump	NPSHA (ft) at 189 °F for DBA-LOCA event	NPSHA (ft) at 212 °F for non-LOCA events	NPSHR (ft) (without uncertainties)
RHR	4.4 (limiting pump)	5.7 (limiting pump)	2.0 (for all pumps)
LPCS	7.0	6.4	1.6
HPCS	8.5	7.0	2.0

The licensee also calculated the peak bulk pool temperature for the non-LOCA ASDC event considering 102 percent reactor power, decay heat as per ANS 5.1-1979 plus 2-sigma added for uncertainty, and assuming availability of one RHR heat exchanger. The licensee stated that the peak bulk suppression pool bulk temperature was found to be 198 °F and is therefore bounded by the RHR pump NPSH limit of 210 °F for the ASDC event. In NRC staff RAIs, the licensee was referred to fourth paragraph of PUSAR Section 2.6.5.1, and was requested to provide the values of NPSHA at 198 °F and the NPSHR (including uncertainties) for the RHR pump during the non-LOCA ASDC event. The licensee was also requested to provide the limiting values of NPSHA for ECCS pumps during the three events, ATWS, SBO, and

Appendix R, listed in PUSAR Table 2.6-3. The licensee was also requested to provide a comparison with the current values of available and required NPSH for these events. In its response dated March 31, 2011, the licensee stated that the CLB NPSH evaluation for non-LOCA events considered a conservative suppression pool temperature of 212 °F which bounds the peak bulk suppression pool temperature of 198 °F for the ASDC event and 200.1 °F for the SBO event. The licensee stated that containment accident pressure was not credited in the NPSHA calculation. The NRC staff agrees that the CLB NPSH evaluation for non-LOCA events remains unchanged for EPU implementation. Table 2.6.5-1 above provides the values of NPSHA at suppression pool temperature of 212 °F for non-LOCA events for ECCS pumps.

In an NRC staff RAI, the licensee was requested explain or remove a conflict between the statement in PUSAR Section 2.6.5.2 and Table 2.6-1. The first paragraph of Section 2.6.5.2 states that no change in the suppression pool temperature results from the implementation of EPU. However Table 2.6-1 lists the peak suppression pool temperature for EPU DBA LOCA as 189 °F compared to the current value of 181 °F. The licensee was also requested to provide the reduction in the NPSH margin by EPU implementation. In its response dated March 31, 2011, the licensee stated that the statement in question misstated the impact on the suppression pool temperature. The statement is being clarified to state:

> With the exception of the SP temperature, there are no changes to any of these parameters due to the implementation of EPU. The maximum SP temperature for the DBA LOCA has increased from 181 °F to 189 °F for EPU; the maximum SP temperature for any non-LOCA event is 200.1 °F.

The licensee calculated the reduction in NPSH margin to be 3.5 ft for a LOCA peak suppression pool temperature which increases from 181 °F at CLB conditions to 189 °F at EPU conditions. The licensee noted that the CLB LOCA NPSHA evaluation was performed based on a pool temperature of 185 °F; thus, the reduction in NPSHA margin from the current values is 1.9 ft.

In an NRC staff RAI, the licensee was requested to provide the basis for the values of NPSHR that was used to compare with the NPSHA for the ECCS pumps. The licensee was also requested to provide uncertainties that were included in the evaluation of the NPSHR from the NPSHR provided by the pump vendor. In its response dated March 31, 2011, the licensee stated that NPSHR is a design characteristic associated with a particular pump, provided by the pump vendor and obtained by testing along with the pump flow-head curve. The licensee further stated that no evaluation of uncertainties was performed for EPU on the pump vendors NPSHR values; rather, conservative assumptions of post-accident conditions were considered in the calculation of the NPSHA, including: pool temperature, calculated suppression pool level response, pump runout flow, and suction strainer debris loading. In addition, no credit was taken for containment pressure developed during the accident. Table 2.6.5-1 provides the NPSHR values for the ECCS pumps provided by the licensee. These values are the required head at a reference datum that is 3 feet above the pump mounting flange. The NRC staff concludes that the NPSH evaluation is acceptable because the licensee used conservative assumptions and inputs for calculating NPSHA, and demonstrated sufficient margin between NPSHA and NPSHR while not taking any credit for the containment accident pressure.

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 concludes that the systems will continue to meet GDC 38 with respect to rapidly reducing the containment pressure and temperature following a LOCA and maintaining them at acceptably low levels. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to containment heat removal systems.

2.6.6 Secondary Containment Functional Design

Regulatory Evaluation

The secondary containment structure and supporting systems are provided to collect and process radioactive material that may leak from the primary containment following an accident. The supporting systems maintain a negative pressure during accidents within the secondary containment and process this leakage. The NRC staff's review covered (1) analyses of the pressure and temperature response of the secondary containment following accidents within the primary and secondary containments, (2) analyses of the effects of openings in the secondary containment on the capability of the depressurization and filtration system to establish a negative pressure in a prescribed time, (3) analyses of any primary containment leakage paths that bypass the secondary containment, (4) analyses of the pressure response of the secondary containment resulting from inadvertent depressurization of the primary containment when there is vacuum relief from the secondary containment, and (5) the acceptability of the mass and energy release data used in the analysis. The review primarily focused on the effects that the proposed EPU may have on the pressure and temperature response and drawdown time of the secondary containment and the impact this may have on offsite dose. The NRC's acceptance criteria for secondary containment functional design are based on (1) GDC 4, "Environmental and dynamic effects design bases," insofar as it requires that SSCs important to safety be designed to accommodate the effects of environmental conditions associated with normal operation, maintenance, testing, and postulated accidents and be protected from dynamic effects (e.g., the effects of missiles, pipe whipping, and discharging fluids) that may result from equipment failures, and (2) GDC 16, "Containment design," insofar as it requires that reactor containment and associated systems be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment. SRP Section 6.2.3, "Secondary Containment Functional Design" (Reference 62), contains specific review criteria.

Technical Evaluation

The standby gas treatment system (SGTS) is a secondary containment supporting system that maintains the secondary containment at a negative pressure and removes the fission products by filtering the exhaust air during abnormal conditions to limit the offsite dose.

An increase in the RTP will increase the heat load on the secondary containment and affect its drawdown time. The drawdown time is the time required for the secondary containment to achieve the necessary negative pressure following the start of the accident which is assumed to result in releases from the primary containment directly to the environment without filtering. In an NRC staff RAI, the licensee was requested to provide an evaluation of the effect of increased secondary containment heat load on the drawdown time and offsite dose. In its response (Reference 18) the licensee stated that in the current calculation, the worst case post-accident steady state reactor building volume average temperature is calculated to be 107.6°F which was rounded up to 110°F for the drawdown calculation. For EPU, this average temperature is calculated to be 108.1°F. Therefore, the increase in the average temperature is bounded by the temperature on which the current drawdown calculation is based, and therefore the results of the current calculation are valid for this EPU implementation. Regarding the impact on the offsite dose, the licensee stated that the SGTS flow rate, the primary containment leakage rate, and the SGTS radionuclide retention efficiency are not adversely affected by EPU implementation. Based on the above, the NRC staff agrees with the licensee that the licensee's current analysis for drawdown time and offsite dose is bounded with respect to the rise in secondary containment heat load due to EPU implementation.

The licensee stated that the capability of SGTS to minimize the ex-filtration of air from the reactor building is [[

]].

The licensee stated that there is no increase in mass and energy released to secondary containment because the maximum reactor dome pressure is not changed for EPU. The NRC staff agrees with the licensee's evaluation.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the secondary containment pressure and temperature transient and the ability of the secondary containment to provide an essentially leak-tight barrier against uncontrolled release of radioactivity to the environment. The NRC staff concludes that the secondary containment and associated systems will continue to provide an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment following implementation of the proposed EPU. The NRC staff also concludes that the secondary containment and associated systems will continue to meet the requirements of [current licensing basis] GDC 4 and 16. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to secondary containment functional design.

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

The NRC staff reviewed the control room habitability system and control building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. Another 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 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 (1) 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 postulated accidents, including the effects of the release of toxic gases, and (2) GDC 19, "Control room," 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 0.05 sievert (Sv) (5 roentgen equivalent man (rem)) total effective dose equivalent (TEDE) as defined in 10 CFR 50.2, "Definitions," for the duration of the accident. SRP Section 6.4, "Control Room Habitability System" (Reference 62), and other guidance in Matrix 7 of RS-001 (Reference 54) contain specific review criteria.

Technical Evaluation

Due to an increase in the radioactive particulates released during the post-accident conditions under EPU, the control room emergency filtration (CREF) is affected. The licensee has implemented alternate source term (AST) methodology at GGNS via Amendment No. 145 dated March 14, 2001 (Reference 152), which affects the iodine release model. The licensee performed the AST EPU analyses at 102 percent of EPU reactor power, incorporating the increased iodine release as well as the effects of the AST iodine release model. In all cases analyzed, the licensee determined that the control room doses were within the regulatory limits. The licensee also evaluated the quantities and locations of gases and hazardous chemicals that could affect the control room and determined that they are unaffected under EPU conditions. The NRC staff concludes that the EPU has no effect on the design-basis potential toxic gas concentrations because the quantity and locations of toxic gas and hazardous chemical release is within the CLB limits.

Conclusion

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

2.7.2 Engineered Safety Feature Atmosphere Cleanup

Regulatory Evaluation

Engineered safety feature (ESF) atmosphere cleanup systems are designed for fission product removal in post-accident environments. These systems generally include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., standby gas treatment system (SGTS) and emergency or post-accident air cleaning systems) for the fuel handling building, control room, secondary containment, 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 ESF atmosphere cleanup systems are based on (1) GDC 19, "Control room," 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 0.05 Sv (5 rem) TEDE as defined in 10 CFR 50.2, "Definitions," for the duration of the accident, (2) GDC 41, "Containment atmosphere cleanup," 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, "Fuel storage and handling and radioactivity control," 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, "Monitoring radioactivity releases," insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs, and postulated accidents. SRP Section 6.5.1, "ESF Atmosphere Cleanup Systems" (Reference 62), contains specific review criteria.

Technical Evaluation

The licensee stated that the standby gas treatment system (SGTS) and CREF system are the only two ESF atmosphere cleanup systems at GGNS. The evaluation of CREF system under EPU conditions is described and reviewed in Section 2.7.1 of this SE. The SGTS provides fission product control during abnormal conditions. The evaluation of the SGTS under EPU conditions is described Sections 2.5.2.1 and 2.6.6 of this SE.

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 also 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 the above, the NRC staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of GDC 19, 41, 61, and 64. Therefore, the NRC staff concludes that the proposed EPU is 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. The NRC's review of the CRAVS focused on the effects that the proposed EPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products and the expected environmental conditions in areas served by the CRAVS. The NRC's acceptance criteria for the CRAVS are based on (1) GDC 4, "Environmental and dynamic effects design bases," insofar as it 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, (2) GDC 19, "Control room," 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 0.05 Sv (5 rem) TEDE as defined in 10 CFR 50.2, "Definitions," for the duration of the accident, and (3) GDC 60, "Control of releases of radioactive materials to the environment," insofar as it requires that the plant design include means to control the release of radioactive effluents. SRP Section 9.4.1, "Control Room Area Ventilation System" (Reference 62), contains specific review criteria.

Technical Evaluation

The CRAVS performs the function of controlling the temperature and humidity conditions suitable for personnel comfort and for equipment operation in the control room. The system also maintains a positive pressure inside the control room to prevent air infiltration. The heat sources for the control room area include heat transmission due to ambient outside air temperature, equipment, and lighting. The licensee stated that these heat loads are not power dependent because EPU implementation does not add equipment to the control room. In an NRC staff RAI, the licensee was requested to inform the NRC staff if EPU will require alteration in any control room equipment that will result in an increased heat load. In its response the licensee stated that modifications for EPU require minimal changes to equipment located within the control room envelope such as strip chart recorder replacements, meter rescaling, changes to switches and their setpoints, none of which have an adverse impact to the control room heat load. As part of the proposed extended power uprate (EPU), the licensee plans to replace the existing analog average power range monitor subsystem of the existing neutron monitoring system with the more reliable digital power range neutron monitoring system (PRNMS). The licensee performed a conservative evaluation of the control room heat load and demonstrated that the maximum expected control room temperature would increase by less than 1 °F and is within the acceptable limits. Therefore installation of the PRNMS equipment will not have an adverse effect on the CRAVS. The licensee determined that EPU implementation will not affect the equipment located in rooms adjacent to the control room, and therefore does not affect the main control room heat load.

The licensee stated that EPU implementation will not result in an increase in toxic gas release. The post-accident control of the concentration of airborne radioactive material in the control room area is accomplished by the system described and evaluated in Section 2.7.1. The NRC staff agrees with the licensee's evaluation stating that CRAVS does not require system configuration or system parameters changes as a result of EPU because the heat load and toxic gas release are not affected by EPU implementation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room components. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from a DBA under the conditions of the proposed EPU and associated changes to parameters affecting environmental conditions for control room personnel and equipment. Accordingly, the NRC staff concludes that the CRAVS will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed EPU. Based on the above, the NRC staff concludes that the CRAVS will continue to meet the requirements of GDC 4, 19, and 60. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the CRAVS.

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 SFP 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, "Control of releases of radioactive materials to the environment," insofar as it requires that the plant design include means to control the release of radioactive effluents, and (2) GDC 61, "Fuel storage and handling and radioactivity control," insofar as it requires that systems that contain radioactivity be designed with appropriate confinement and containment. SRP Section 9.4.2, "Spent Fuel Pool Area Ventilation System" (Reference 62), contains specific review criteria.

Technical Evaluation

The SFPAVS is a sub-system of the auxiliary building ventilation system (ABVS). The SFPAVS provides ventilation for the fuel handling area and maintains a slightly negative pressure with respect to surrounding areas during normal operation to ensure that airborne radiation is collected by the system. In PUSAR Section 2.5.3.1.1, the licensee stated that the fuel pool temperatures will be maintained within the CLB limits under EPU conditions by the safety-related fuel pool cooling system. Therefore, the heat loads due to increased decay heat in the fuel pool will not adversely affect the temperatures in the fuel handling area. During abnormal operation, the SGTS is initiated which maintains the negative pressure and performs filtration of the exhaust air through ESF filters. The safety evaluation of ABVS including SFPAVS is provided in Section 2.7.5 of this report, and the safety evaluation of the SGTS is given in Section 2.6.6 of this report.

Conclusion

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

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

Regulatory Evaluation

The function of the auxiliary and radwaste area ventilation system (ARAVS) and the turbine area ventilation system (TAVS) is to maintain ventilation in the auxiliary and radwaste equipment and turbine areas, permit personnel access, and control the concentration of airborne radioactive material in these areas during normal operation, during AOOs, and after postulated accidents. The NRC staff's review focused on the effects of the proposed EPU on the functional performance of the safety-related portions of these systems. The NRC's acceptance criteria for the ARAVS and TAVS are based on GDC 60, "Control of releases of radioactive materials to the environment," insofar as it requires that the plant design include the means to control the release of radioactive effluents. SRP Sections 9.4.3, "Auxiliary and Radwaste Area Ventilation System," and 9.4.4, "Turbine Area Ventilation System" (Reference 62), contain specific review criteria.

Technical Evaluation

The ARAVS and TAVS consist mainly of heating, cooling, supply, exhaust, and recirculation units serving the drywell, auxiliary building, radwaste building, and turbine building.

The licensee stated that the normal operating process temperatures under EPU conditions that affect the heating or cooling loads for the ARAVS and TAVS are bounded by the current temperatures with the exception of increase in feedwater temperature in some portions of the system. In the current analysis, the design feedwater temperature used by the licensee to determine the heat load bounds the EPU feedwater temperature. For EPU no modification is required for pump motors that would result in increased heat loads. Therefore, the current ARAVS and TAVS are unaffected by EPU. The NRC staff concludes that ARAVS and TAVS are unaffected by EPU, because no modifications in equipment are necessary that would affect the heat loads and any load increase due to higher feedwater temperature are bounded by the current design heat load.

Conclusion

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

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 of 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, "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, (2) GDC 17, "Electric power systems," insofar as it requires that onsite and offsite electric power systems be provided to permit functioning of SSCs important to safety, and (3) GDC 60, "Control of releases of radioactive materials to the environment," insofar as it requires that the plant design include the means to control the release of radioactive effluents. SRP Section 9.4.5, "Engineered Safety Feature Ventilation System" (Reference 62), contains specific review criteria.

Technical Evaluation

The ESFVS consist mainly of heating, cooling, exhaust, and recirculation units serving the safeguard switchgear and battery rooms, diesel generator rooms, station service water (SSW) system pump-houses, and the following areas of the auxiliary building: ECCS pump rooms, ESF electrical switchgear rooms, and the fuel pool cooling and cleanup system (FPCCS) pump room. The licensee stated that during normal plant operation under EPU conditions, the ESFVS serving these areas are unaffected because the process temperatures remain bounded by the CLB conditions. The licensee further stated that during post-accident conditions with loss of offsite power and loss of non-safety-related heating ventilation and air conditioning (HVAC) systems, due to higher suppression pool temperature, the temperature in the ECCS pump rooms will increase between 2 °F and 9 °F, the temperature in the ESF electrical switchgear room will increase by a maximum of 2 °F, and the temperature of the FPCCS pump room is unaffected. The licensee has accounted for these temperature increases in the auxiliary building in the environment qualification of the safety-related equipment located in these rooms. Section 2.3.1 of PUSAR provides the licensee's evaluation of environmental qualification of this equipment which is reviewed in Section 2.3.1 of this SE.

Conclusion

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

2.8 Reactor Systems

GGNS is a BWR/6 design and is currently licensed to operate at a maximum reactor power level of 3898 MWt. The licensee, in conjunction with GEH, undertook a program to uprate the maximum reactor power level by approximately 13 percent above the current licensed power level to 4408 MWt.

The GGNS safety analysis of the proposed EPU is provided in the PUSAR. This report describes in general, the plant's ability to operate at the higher power level and to respond to AOOs, transients and accident conditions as designed and analyzed. The licensee also evaluated the effect of the increased thermal power on the capability and performance of systems, structures, and components important to safe operation of the plant.

Based on the EPU experience, GEH developed an approach to uprate reactor power that maintains the current plant maximum normal operating reactor dome pressure. This approach is based on the CLTR and the NRC staff's SE for the CLTR dated March 31, 2003. The CLTR provided appropriate guidelines for constant pressure EPU applications with a core exclusively using GE fuel types through GE14 and using GEH accident analysis methods. Some topics in the CLTR are directly fuel dependent because the fuel type affects the resulting evaluation or the consequences of transients or accidents. GGNS contains only GE fuel types, through and including GNF2, and the EPU evaluation uses only GEH accident analysis methods. Because GGNS uses GNF2 fuel, the CLTR is not applicable for fuel design dependent evaluations, consistent with the "Conditions and Limitations" identified in the NRC staff's SE for using the CLTR. For the fuel-dependent topics, the evaluation methods from ELTR1 and ELTR2 are applied. In general, the licensee's plant-specific engineering evaluations supporting the power uprate were performed in accordance with guidance contained in ELTR1. This topical report was previously reviewed and endorsed by the NRC staff. For some items, bounding analyses and evaluations provided in ELTR2 were cited.

The NRC staff has approved ELTR2. The ELTR2 generic evaluations assume (a) a 20 percent increase in thermal power, (b) an increase in operating dome pressure up to 1,095 psia, a reactor coolant temperature increase to 556 °F, and (d) a steam and feedwater flow increase of about 24 percent.

The approach to achieving the EPU consists of (1) an increase in the core thermal power with a more uniform power distribution achieved by better fuel management techniques to create increased steam flow, (2) a corresponding increase in the feedwater system flow, (3) no increase in maximum core flow, and (4) reactor operation primarily along the maximum extended load line limit analysis (MELLLA) rod/flow lines. This approach is based on, and is consistent, with the NRC-approved BWR EPU guidelines.

An increase in the electrical output of a BWR is accomplished primarily by supplying a higher steam flow to the turbine generator. Most GE BWRs, as originally licensed, have as-designed equipment and system capability to accommodate steam flow rates at least 5 percent above the original rating. In addition, continuing improved analytical techniques and computer codes, operating experience, and improved fuel designs have resulted in an increase in the design and operating margins, between the results of the safety analysis calculations and the licensing limits. The larger margins combined with the as-designed excess equipment, system, and component capabilities, have allowed many BWRs to increase their thermal power ratings by 5 percent (stretch uprate) without modifying any nuclear steam supply system (NSSS) hardware and to increase power up to 20 percent (extended power uprate) with some hardware modifications. These power increases do not significantly increase the hazards of the plants as originally licensed.

The proposed GGNS EPU will not increase the operating pressure or the current licensed maximum core flow. EPU operation will not increase reactor vessel dome pressure because the plant has made, or will make modifications to the power generation equipment, pressure controls and turbine flow capabilities to control the pressure at the turbine inlet.

The NRC staff's review of the GGNS EPU LAR used applicable rules, regulatory guides, SRP sections, and NRC staff positions on the topics being evaluated. The NRC staff also used RS-001 (Reference 54).

The scope of the NRC staff's review for the GGNS EPU request included, "lessons learned" from past power uprate amendment reviews. In reviewing the licensee's request for an EPU, the NRC staff considered the recommendations of the report of the Maine Yankee Lessons Learned Task Group (SECY-97-042, "Response to OIG [Office of the Inspector General] Event Inquiry 96-04S Regarding Maine Yankee," dated February 18, 1997 (Reference 153)). The task group's main findings centered on the use and applicability of the computer codes and analytical methodologies used for power uprate evaluations. The NRC staff requested that the licensee identify all codes and methodologies used to obtain safety limits and operating limits and explain how they verified these limits were correct for the uprate core. The licensee was also requested to identify and discuss any limitations imposed by the NRC staff on the use of these codes and methodologies.

In the operating cycle in which EPU will be first implemented (Cycle 19), there will be only GE fuel types, through and including GNF2. The EPU safety analyses and the cycle-specific reload analyses will be performed in accordance with NRC-approved GE analytical methodologies described in the latest version of GESTAR II (Reference 154). The licensing topical reports specifying the codes and methodologies used for performing the safety analyses are documented in the GGNS TSs. The limiting AOO and accident analyses are reanalyzed or confirmed to be valid for every reload and the safety analyses of transients and accidents are documented in Chapter 15 of the GGNS UFSAR. Limiting transient or accident analyses are generally defined as analyses of events that could potentially affect the core operating and safety limits that ensure the safe operation of the plant.

In the GGNS EPU submittal, the licensee referenced the GE LTR, NEDC-33173P, "Applicability of GE Methods to Expanded Operating Domains," February 2006 (Reference 60) The NRC staff requested the licensee to provide additional information and evaluated several areas related to application of GE methods used for EPU evaluations at GGNS, consistent with the NRC staff SER for NEDC-33173P (Reference 155). The license agreed to take penalties on certain parameters for GGNS EPU operation. The result of our evaluation in this area is given in Section 2.8.7 of this SE input.

2.8.1 Fuel System Design

Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, channel boxes, and reactivity control rods. The NRC staff reviewed the fuel system to ensure that:

1. The fuel system is not damaged as a result of normal operation and AOOs[1];

2. Fuel system damage is never so severe as to prevent control rod insertion when it is required;

3. The number of fuel rod failures is not underestimated for postulated accidents[2] (PAs); and

4. Coolability of the core is always maintained.

5. The NRC staff's review covered fuel system damage mechanisms, limiting values for important parameters, and performance of the fuel system during normal operation, AOOs, and PAs.

The NRC's acceptance criteria are based on 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," insofar as it establishes acceptance criteria, and standards for the calculation and evaluation of emergency core cooling system (ECCS) performance; GDC 10, "Reactor design," 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; GDC 27, "Combined reactivity control systems capability," 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 GDC 35, "Emergency core cooling," insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA.

Specific review criteria are contained in SRP Section 4.2, "Fuel System Design" (Reference 62), and other guidance is provided in Matrix 8 of RS-001 (Reference 54).

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[1] AOOs, or incidents of moderate frequency, are defined in Appendix A to 10 CFR Part 50. AOOs are those conditions of normal operation that are expected to occur one or more times during the life of the nuclear power unit. This definition groups infrequent events into the AOO category.

[2] PAs, or limiting faults, are unanticipated occurrences (i.e., they are postulated; but not expected to occur during the life of the nuclear power plant).

Technical Evaluation

GGNS transitioned to GNF2 fuel in Cycle 18. Hence, GNF2 fuel is currently resident in the GGNS core. The core design for EPU implementation cycle (Cycle 19) will include only GE fuel types. The GGNS EPU application assumes an equilibrium core of GNF2. GGNS will introduce no new fuel products to implement the EPU, and that there are no changes required by EPU to the fuel design limits that were licensed in accordance with the General Electric Standard Application for Reactor Fuel (GESTAR II) design change process (Reference 154). The NRC staff reviewed the application of the GESTAR II process for GNF2 to determine the acceptability of the fuel system design for the proposed GGNS EPU.

The fuel vendor for GGNS is Global Nuclear Fuel (GNF), which is a business entity of GEH. GNF follows their licensed GESTAR II design change process, to introduce new fuel assembly designs. The GESTAR II process allows GNF to make significant design changes without specific NRC staff review. However, this process includes a requirement to provide an advance notification, which affords the NRC staff the opportunity to perform an audit. GNF is also required to supply the NRC staff with a report showing that the new fuel design conforms to the NRC approved fuel design criteria ("GESTAR II compliance report").

In January 2008, the NRC staff performed an audit to evaluate the new design features of the GNF2 fuel design and to confirm that this design satisfies all of the fuel design criteria. As a part of this audit, the NRC staff performed a review of the GESTAR II compliance report for GNF2, March 2010 (Reference 156), and the new critical heat flux (CHF) correlation GEXL17, March 2007 (Reference 157). The NRC staff's audit findings dated January 2008 and August 4, 2009, are documented in References 158 and 159, respectively. During this audit, the NRC staff identified open items in the area of thermal-mechanical (T-M) design and analysis. To this end, GNF had addressed the NRC staff open items on an interim basis through Amendment 32 to GESTAR II (References 160 and 161). The NRC staff has subsequently reviewed the PRIME T-M methodology and documented its approval in its SE dated January 22, 2010 (Reference 162). The application of the PRIME T-M methodology (Reference 163) within the conditions of its approval removes the previously imposed restrictions on GNF2. The GNF2 fuel system design evaluation for GGNS EPU application has been performed using the updated PRIME T-M methods (Reference 164).

This information confirms that GGNS will continue to comply with the NRC-approved fuel design limits at the proposed EPU conditions. In addition, as discussed in Section 2.8.5, "Accident and Transient Analyses," of this SE, the NRC staff concludes that the licensee has adequately addressed the effect of EPU on accident and transient analyses.

Conclusion

The NRC staff has reviewed the licensee's disposition related to the effects of the proposed EPU on the design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the fuel system and demonstrated that

1. The fuel system will not be damaged as a result of normal operation and AOOs;

2. The fuel system damage will never be so severe as to prevent control rod insertion when it is required;

3. The number of fuel rod failures will not be underestimated for PAs; and

4. Coolability of the core will always be maintained.

These considerations are based, in large part, on the fact that the fuel design does not change for the EPU, and that the generic fuel design is appropriate for the GGNS EPU operating conditions.

Based on the above, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," GDC 10, GDC 27, and GDC 35 following implementation of the proposed EPU and is, therefore, acceptable.

2.8.2 Nuclear Design

Regulatory Evaluation

The NRC staff reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and AOOs and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core.

The NRC staff's review covered:

1. Core power distribution,

2. Reactivity coefficients,

3. Reactivity control requirements and control provisions,

4. Control rod patterns and reactivity worths,

5. Criticality,

6. Burnup, and

7. Vessel irradiation.

The NRC's acceptance criteria are based on GDC 10, "Reactor design," 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 the effects of AOOs; GDC 11, "Reactor inherent protection," 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; GDC 12, "Suppression of reactor power oscillations," 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; GDC 13, "Instrumentation and control," 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; GDC 20, "Protection system functions," 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; GDC 25, "Protection system requirements for reactivity control malfunctions," 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 26, "Reactivity control system redundancy and capability," insofar as it requires that two independent reactivity control systems of different design principles be provided, and that one of the systems be capable of holding the reactor subcritical in the cold condition; GDC 27, "Combined reactivity control systems capability," 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 GDC 28, "Reactivity limits," insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core.

Specific review criteria are contained in SRP Section 4.3, "Nuclear Design" (Reference 62), and other guidance is provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

GGNS addresses several aspects of the nuclear design for the proposed EPU conditions, including:

1. Core Design

2. Fuel Thermal Margin Monitoring

3. Thermal Limits

4. Reactivity Characteristics

5. Interim Methods Applicability

Items 1-4 are addressed by the NRC staff in the present evaluation. Item 5, concerning the applicability of interim methods, is addressed in Section 2.8.7 of this SE.

Core Design

The implementation of the EPU will increase the average power density of the core by increasing bundle enrichment and reload fuel batch size, and/or changing the fuel loading pattern. The required changes are implemented in such fashion as to limit the impact on fuel safety parameters, which include the minimum critical power ratio (MCPR), the linear heat generation rate (LHGR), and the maximum average planar linear heat generation rate (MAPLHGR).

As discussed in Section 2.8.1, the EPU requires no changes to the fuel design limits that were licensed in accordance with the GESTAR II process. The acceptability of the core nuclear design also depends upon obtaining acceptable results for transient and accident analyses, at the proposed EPU conditions. As discussed in Section 2.8.5, "Accident and Transient Analyses," the NRC staff concludes that the licensee has acceptably addressed the effect of EPU on accident and transient analyses.

By letter dated December 28, 2010 (Reference 165), the NRC staff issued the SER for NEDC-33173P Supplement 3, "Applicability of GE Methods to Expanded Operating Domains – Supplement for GNF2 Fuel". The NRC staff concluded that all other NRC staff guidance, limitations, and conclusions documented in the SE for the IMLTR remain applicable for GNF2 as originally stated. The NRC staff concludes that the qualification provided in Supplement 3 demonstrates equivalent performance of the GEH methods suite to analyze GNF2 as that demonstrated for GE14 fuel. This included the neutronic, thermal-hydraulic, and T-M aspects of the methods. Therefore, the NRC staff concludes that the extension of the approval of the interim methods process to GNF2 fuel acceptable. The NRC staff evaluation of IMLTR for GGNS in Section 2.8.7 of this SE concludes that the GGNS complies with all applicable limitations and conditions.

Based on above, the NRC staff concludes that the GGNS core design is acceptable for the proposed EPU conditions.

Fuel Thermal Margin Monitoring

The GGNS TSs require monitoring for margin to the fuel thermal limits. For example, LCO 3.2.1 requires that all average planar linear heat generation rates (APLHGRs) be less than or equal to the limits specified in the COLR. This LCO, and all other LCOs that pertain to the fuel thermal limits, applies whenever thermal power is greater than or equal to 25 %RTP (i.e., the fuel thermal margin monitoring threshold).

Since fuel thermal margin monitoring is at the **[[**

]].

Therefore, for the uprated GGNS core, the fuel thermal margin monitoring threshold is scaled down such that monitoring is initiated [[ ]]. Thus, the fuel thermal margin monitoring threshold value is reduced by a factor of 1.2/(0.25*EPU RTP). The GGNS fuel thermal monitoring threshold value is set at 21.8 percent of EPU RTP (25%*(1.2/(0.25 * 4408 MWt / 800 bundles)).

Below 25% RTP, there is a high margin on critical power. Transients, initiated at lower power levels (e.g., from 20% RTP) would not produce any limiting consequences.

The NRC staff concludes that the licensee has provided adequate information to support their determination of the fuel thermal margin monitoring threshold, as rescaled to the proposed EPU conditions.

Thermal Limits Assessment

Section 2.8.2.2 of the PUSAR (Reference 57) addresses the effect of the proposed EPU on the MCPR safety and operating limits and on the MAPLHGR and LHGR limits. The licensee must ensure that plant operation is in compliance with the cycle-specific thermal limits (safety limit minimum critical power ratio (SLMCPR)), operating limit minimum critical power ratio (OLMCPR), MAPLHGR, and maximum LHGR) and specify thermal limits in a cycle-specific COLR as required by GGNS TSs.

The NRC's acceptance criteria require that the reactor core and the associated control and instrumentation systems be designed with appropriate margin to ensure that the SAFDLs are not exceeded during normal operation, including AOOs. Operating limits are established to assure that regulatory or safety limits are not exceeded for a range of postulated events (transients and accidents).

The SLMCPR ensures that 99.9 percent of the fuel rods are protected from boiling transition during steady-state operation. The OLMCPR assures that the SLMCPR will not be exceeded as result of an AOO.

Prior EPU evaluations have shown that the change in OLMCPR that would result solely from the EPU would be small. The OLMCPR will be determined for plant cycle-specific core design parameters using approved methods, as discussed in the PUSAR. As required by the cycle-specific reload licensing requirements, the licensee will perform plant cycle-specific reload analyses to establish the OLMCPR and MAPLHGR and LHGR operating limits, and demonstrate that the SLMCPR provides the appropriate safety margin for fuel cladding integrity.

The licensee stated that there can be a small increase in SLMCPR (less than 0.01), when operating at the higher EPU power level, due to a flatter power distribution. The SLMCPR analysis reflects the actual plant core-loading pattern and is performed for each plant reload core. The calculated values will be reported in the Supplemental Reload Licensing Report (SRLR) for the EPU core. The licensee also stated that the SLMCPR for single-loop operation will normally be 0.01 or 0.02 greater than the SLMCPR for two-loop operation. The licensee discussed the NRC staff's limitation 9.4 of GEH NEDC 33173P-A, "Applicability of GE Methods to Expanded Operating Domains," also known as Interim Methods Licensing Topical Report

(IMLTR), requiring a 0.02 adder to the calculated cycle-specific value for both the single-loop and two-loop SLMCPR. This change has been considered in the Cycle 19 reload analyses and by LAR dated October 28, 2011 (Reference 166), changes to the GGNS TSs were proposed for the Cycle 19 reload MCPR values. The LAR was approved by the NRC staff by Amendment No. 189 dated April 20, 2012 (Reference 167).

The NRC staff concludes that the licensee's assessment of SLMCPR limits acceptable for GGNS EPU. The NRC staff's conclusion in this regard is based on the fact that the SLMCPR is analyzed using NRC-approved methods described in the IMLTR, and its applicability will be confirmed on a cycle-specific basis.

The licensee will evaluate the OLMCPR as part of the reload licensing analysis performed for the cycle-specific core design. The OLMCPR is determined on a cycle-specific basis using NRC-approved methods, and the method does not change with the EPU. The licensee stated that the EPU operating conditions have only a small effect on the MCPR Operating Limit. The OLMCPR is calculated by adding the change in MCPR due to the limiting AOO event to the SLMCPR. The licensee proposed to include a 0.01 OLMCPR adder to the calculated OLMCPR as required by the NRC staff limitation 9.19 of IMLTR.

The NRC staff concludes that the licensee's assessment of OLMCPR limits is acceptable for GGNS EPU because the OLMCPR will be reassessed on a cycle-specific basis using NRC-approved reload licensing methods.

The MAPLHGR operating limit is based on the most limiting LOCA conditions, and ensures compliance with the ECCS acceptance criteria in 10 CFR 50.46. For every reload, licensees confirm that the MAPLHGR operating limit for each reload fuel bundle design remains applicable. The GGNS EPU application, the ECCS performance evaluation based on GNF2 reference equilibrium cycle showed that no change in the MAPLHGR limit is required for EPU for SLO or dual recirculation loop operation (DLO). Since the MAPLHGR Operating Limit is established in accordance with approved methodology for each core reload, the licensee's assessment of this topic for GGNS EPU is acceptable.

The licensee stated in the PUSAR that the Maximum LHGR Operating Limit is determined by the fuel rod thermal mechanical design and is not affected by EPU. Since the Maximum LHGR Operating Limit is established in accordance with approved methodology for each core reload, the assessment of this topic for GGNS EPU is acceptable.

Reactivity Characteristics

The higher core energy requirements of a power uprate may affect the hot excess core reactivity and can also affect operating shutdown margins. The effect of a power uprate on core reactivity is described in Section 5.7.1 of ELTR1. Based on experience with previous plant-specific power uprate submittals, the required hot excess reactivity and shutdown margin can typically be achieved for power uprates through the standard approved fuel and core reload design process. Plant shutdown and reactivity margins must meet NRC-approved limits established in GESTAR II on a cycle-specific basis and these are evaluated for each plant reload core. Additional hot excess reactivity and shutdown margin analyses are not specifically required for the EPU.

The reload core analysis will ensure that the minimum shutdown margin requirements are met for each core design and that the current design and TS cold shutdown margin will be met. Since the licensee will continue to confirm that the TS cold shutdown requirements will be met for each reload core operation, the NRC staff concludes that this acceptable, and concludes that the NRC's acceptance criteria, outlined in Section 2.8.2.1, will continue to be satisfied.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the nuclear design, including core design, fuel thermal margin monitoring, thermal limits, reactivity characteristics, and IMLTR applicability. The licensee will continue to perform plant-specific reload analyses to confirm that SAFDLs and RCPB pressure limits will not be exceeded during the planned cycles. The NRC staff also concludes that the licensee's conclusions regarding the fuel system design, thermal and hydraulic design, and transient and accident analyses are acceptable. In addition, as described in Section 2.8.7 of this SE, the NRC staff concludes that GGNS complies with all applicable limitations and conditions regarding the NRC staff approval of the interim methods process to GNF2 fuel.

Based on above, 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 and, therefore, is acceptable to the NRC staff.

2.8.3 Thermal and Hydraulic Design

Regulatory Evaluation

The purpose of the review of thermal and hydraulic design of the core and the RCS is to ensure that SAFDLs are not exceeded during steady state operation and analyzed transients. The fuel cladding is one of the physical barriers that separate the radioactive materials from the environment. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Fuel cladding perforations can result from thermal stresses, which can occur from reactor operation significantly above design conditions. Since the parameters that result in fuel damage are not directly observable during reactor operation, thermal and hydraulic conditions that result in the onset of transition boiling have been used to mark the beginning of the region in which fuel cladding damage could occur.

The NRC staff's acceptance criteria are based on GDC 10, "Reactor design," which states that the reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs, and GDC 12, "Suppression of reactor power oscillations," which states that the reactor and associated coolant, control, and protection systems shall be designed to assure that power oscillation which can result in conditions exceeding SAFDLs are not possible or can be reliably and readily detected and suppressed.

Specific review criteria are contained in SRP Section 4.2, "Fuel System Design," which specifies all fuel damage criteria for evaluation of whether fuel designs meet the SAFDLs; SRP Section 4.4, "Thermal Hydraulic Design," which provides guidance on the review of thermal-hydraulic design in meeting the requirement of GDC 10 and the fuel design criteria established in Section 4.2, and SRP Section 15.9, "Boiling Water Reactor Stability," provides guidance on the review of the BWR stability in meeting the requirements of GDCs 10, 12, 13, 20, and 29.

Technical Evaluation

Option III

The CLTR states that the Option III trip setpoint may be affected by EPU operating conditions. The Oscillation Power Range Monitor (OPRM) trip-enabled region will be rescaled with EPU.

GGNS has requested to be licensed for the Option III long-term stability solution. This feature is a part of the Power Range Neutron Monitoring System (PRNMS). GGNS currently operates with the Option E1A stability solution, which is described in NEDO-32339-A, Revision 1, Reactor Stability Long-Term Solution: Enhanced Option I-A, dated April 1998 (Reference 168). The transition from Option E1A to Option III is to take place during the spring 2012 refueling outage with the removal of the GGNS neutron monitoring system hardware used for Option E1A and the installation of the new PRNMS, which is required for Option III.

Option III is a detect-and-suppress solution, which combines closely spaced LPRM detectors into "cells" to effectively detect either core-wide or regional modes of reactor instability. These cells are termed OPRM cells and are configured to provide local area coverage with multiple channels. The GGNS Option III hardware combines the LPRM signals and evaluates the cell signals with instability detection algorithms. The Period Based Detection Algorithm (PBDA) is the only algorithm credited in the Option III license basis. Two defense-in-depth algorithms, referred to as the Amplitude Based Algorithm (ABA) and the Growth Rate Algorithm (GRA), offer a higher degree of assurance that fuel failure will not occur as a consequence of stability related oscillation. Plant implementing Option III must demonstrate that the Option III trip setpoint is adequate to provide SLMCPR protection for anticipated reactor instability. This evaluation is dependent upon the core and fuel design and is performed for each reload.

The GGNS OPRM system provides inputs to an associated reactor protection system (RPS) channel via eight OPRM modules. The OPRM modules are installed in available locations in the associated LPRM pages in the power range neutron monitoring system (PRNMS) panels. Each OPRM channel takes amplified LPRM signals from one APRM group and either another APRM group or one unassigned LPRM group. The LPRM signals are grouped together such that the resulting OPRM response provides adequate coverage of anticipated oscillation modes. Stability Long Term Solution Option III consists of hardware and software that provides for reliable, automatic detection and suppression of stability related power oscillations.

The OPRM trips will be enabled for GGNS are the licensing basis Period Based Detection Algorithm (PBDA) as well as for the Growth Rate Algorithm (GRA), and Amplitude Based Algorithm (ABA) defense-in-depth features. The algorithms for the long-term solution (LTS) Option III solution are described in NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications." The OPRM amplitude setpoint calculation is comprised of three components as defined in NEDO-32465-A. The calculation for hot channel oscillation magnitude (HCOM) is performed using the approved GE methodology, and the generic DIVOM (delta CPR over initial CPR versus oscillation magnitude) calculations performed in NEDO-32465-A used the earlier TRACG02 version and pre-PANAC11 neutronic method. In a similar application to other plants, GE has performed an evaluation comparing the use of TRACG04-PANAC11 versus TRACG02-PANAC10 in the calculation of DIVOM slopes and determined that results are essentially the same. Cycle-specific setpoint calculations are now performed to determine the operating MCPR needed to protect the SLMCPR for the various OPRM amplitude setpoints. The Option III trip is armed only when plant operation is within the Option III trip-enabled region. The Option III trip-enabled region for GGNS is defined as the region on the power/flow map with power ≥ 26 percent and ≤ 60 percent rated reactor recirculation drive flow. For constant pressure power uprate (CPPU), the GGNS OPRM trip-enabled region is rescaled to maintain the same absolute power/flow region boundaries. Because the rated core flow is not changed, the 60 percent core flow boundary is not rescaled. The 29 percent CLTP boundary is rescaled to the 26 percent EPU thermal power limit using the CLTP/EPU ratio.

GGNS implements the Backup Stability Protection (BSP) measures as the stability license basis should the Option III OPRM Upscale trip function (APRM Function 2.f of TS Table 3.3.1.1-1) not be operable. The GGNS Option III hardware is being installed during RFO 18 and is required to be implemented prior to ascension to EPU power. The first 90 days of operation during Cycle 19 will be an OPRM monitoring period during which the OPRM trip function is not enabled.

In the event that the OPRM system is declared inoperable, GGNS will use the BWROG Interim Corrective Action (ICA) stability regions as the backup stability protection (BSP) method when the OPRM system is declared to be inoperable. These regions are confirmed on a cycle-specific basis by performing BSP calculations in accordance with the guidance provided in OG02-0119-260, "Backup Stability Protection (BSP) for inoperable Option III Solution," dated July 17, 2002. The GE ODYSY code is used for the calculation of decay ratios based on statepoint and neutronic data from PANAC11 and TGBLA06. If the ODYSY calculations determine that the BSP regions are larger than the corresponding ICA regions, then the larger BSP regions are used for stability monitoring in the event that the OPRM system is declared inoperable. Cycle-specific setpoints and BSP regions are determined and documented in the SRLR. The BSP region intercepts with the Natural Circulation Line (NCL) and with the High Flow Control Line (HFCL) are the same as or more conservative than the ICA region intercepts in absolute power and core flow. The BSP regions consist of two regions (I-Scram and II-Controlled Entry), which are reduced from the three ICA regions (I-Scram, II-Exit and III-Controlled Entry (see BWROG-94078; Reference 169)). A generic evaluation was performed for the ICAs (Section 3.2.1 of ELTR2), which is applicable for EPU. The bounding plant-and cycle-specific BSP region endpoints must enclose the corresponding base BSP region endpoints on the HFCL and the NCL. The proposed BSP Scram and Controlled Entry region boundaries may also be constructed by connecting the corresponding bounding endpoints on the HFCL and NCL using the Modified Shape Function (MSF) (see NEDE-33213P-A; Reference 170).

Based on the review of the licensee's UFSAR and the responses to the NRC staff RAIs dated April 14, 2011 (Reference 14), the NRC staff concludes that the proposed Option III long-term stability solution using OPRM system as a part of the feature of the PRNMS is acceptable because: (1) the approach is based on approved methodologies; (2) the OPRM amplitude setpoints presented in the EPU LAR includes the 0.01 setpoint penalty due to LPRM calibration errors with respect to effect of bypass voids on instrumentation; (3) the DIVOM slope calculated for the EPU equilibrium core is given and the DIVOM slope for Cycle 19 will be provided prior to startup from the spring 2012 refueling outage; and (4) the TS changes to update the PRNMS system TSs to reflect EPU conditions are provided in EPU LAR.

ATWS with Core Instability

The effects of an ATWS with core instability event occur at natural circulation following a recirculation pump trip. It is initiated at approximately the same power level as a result of EPU operation because the MELLLA upper boundary is not increased. The core design necessary to achieve EPU operations may affect the susceptibility to coupled thermal-hydraulic/neutronic core oscillations at the natural circulation condition, but would not significantly affect the event progression. CPPU allows plants to increase their operating thermal power but does not allow an increase in control rod line. Several factors affect the response of an ATWS instability event, including operating power and flow conditions and core design. The limiting ATWS core instability presented in NEDC-32047-A, "ATWS Rule Issues Relative to BWR Core Thermal-Hydraulic Stability," June 1995 (Reference 171), and NEDO-32164, "Mitigation of BWR Core Thermal-Hydraulic Instabilities in ATWS," December 1992 (Reference 172), was performed for an assumed plant initially operating at OLTP and the MELLLA minimum flow point.

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]]. The void reactivity coefficient, fuel response time (fuel rod diameter), and pressure loss coefficients are the parameters important to determining the reactor stability. It also indicates that initial operating conditions of feedwater heater out of service (FWHOOS) and final feedwater temperature reduction (FFWTR) do not significantly affect the ATWS instability response.

The limiting ATWS evaluation assumes that all feedwater heating is lost during the event and injected feedwater temperature approaches the lowest achievable main condenser hot well temperature. **[[**

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GGNS currently applies emergency operating guidelines based on BWR Owners' Group Emergency Procedure and Severe Accident Guidelines, Revision 2 (BWROG EPGs/SAGs). In the event of an ATWS, the operator is directed by GGNS emergency procedures to immediately: (1) initiate standby liquid control (SLC) if reactor power is above 4 percent or the suppression pool temperature is greater than or equal to 110 °F; and (2) lower level to reduce subcooling, while ensuring SLC injection, control rod drive (CRD) and RCIC flows are maintained, if reactor power is above 4 percent or unknown. The first target level is -70 inches, with a second target level at approximately the top of active fuel if the suppression pool temperature exceeds 110 °F.

Based on the above, the NRC staff concludes that the ATWS evaluation and ATWS mitigation strategy for GGNS are acceptable because: (1) the EPU effect on ATWS with core stability at GGNS is consistent with the generic evaluation in the CLTR; (2) the generic evaluation is applicable to GGNS [[ ]] and operator actions are expected to mitigate an ATWS instability event at EPU conditions; (3) the EPU implementation does not change operator strategy on ATWS level reduction or early boron injection; and (4) the EOPs have the BWROG EPGs/SAGs strategy.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on 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 thermal and hydraulic design and demonstrated that the design (1) has been accomplished using acceptable analytical methods, (2) is a proven design, (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 the above, the NRC staff concludes that thermal and hydraulic design will continue to meet the requirements of GDCs 10 and 12 following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to thermal and hydraulic design.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

Regulatory Evaluation

The NRC staff's review covered the functional performance of the control rod drive system (CRDS) to confirm that the system can effect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CRDS cooling system to ensure that it will continue to meet its design requirements. The CRD system is used to control core reactivity by positioning neutron absorbing control rods within the reactor and to scram the reactor by rapidly inserting withdrawn control rods into the core. Alternate rod insertion (ARI) system is not affected by EPU because it has no thermal power dependency.

The NRC's acceptance criteria are based on (1) 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, (2) GDC 23, "Protection system failure modes," insofar as it requires that the protection system be designed to fail into a safe state, (3) GDC 25, "Protection system requirements for reactivity control malfunctions," insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems, (4) GDC 26, "Reactivity control system redundancy and capability," insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes, (5) GDC 27, "Combined reactivity control systems capability," 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 that the capability to cool the core is maintained, (6) GDC 28, "Reactivity limits," 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, (7) GDC 29, "Protection against anticipated operational occurrences," insofar as it requires that the protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in the event of AOOs, and (8) paragraph (c)(3) of 10 CFR 50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants," insofar as it requires that all BWRs have an alternate rod injection (ARI) system diverse from the reactor trip system, and that the ARI system have redundant scram air header exhaust valves. SRP Section 4.6, "Functional Design of Control Rod Drive System" (Reference 62), contains specific review criteria.

Technical Evaluation

Scram Time Response

During normal operation conditions, the HCU accumulator supplies pressure to the CRD to scram. With EPU, the normal reactor dome pressure does not change and so the scram time stays essentially the same. GGNS will retain its current TS scram time requirements.

The higher steam flow associated with EPU increases the pressurization rate during transients. Scram speed is dependent on the reactor pressure response and thus a slower scram time can result. For the AOO analyses, the EPU transient reactor pressure is not bounded by the generic envelope. GGNS stated that because of this they will be implementing Option B scram times to maintain operating margin and address the expected increase in scram times. The Option B scram times come from the MCPR margin improvement options described in GESTAR II. Using Option B scram times refers to the establishment of a less restrictive OLMCPR based on conservative demonstration of AOO analysis results considering actual scram time performance. The option is used when actual scram times are better than those assumed in the transient analyses supporting the TS requirements for scram time performance. GGNS used only TS basis scram speeds in the EPU AOO analyses.

Control Rod Drive Positioning

The increase in reactor power at the EPU operating condition results in a slight increase in the pressure above the core plate of approximately 1 psi that has no effect on the drive water pressure and the cooling water flow rate. The automatic operation of the system flow control valve maintains the required drive water pressure, and the CRD positioning function should not be affected. Regardless, the normal CRD position function is an operational consideration and not a safety-related function.

The licensee stated that the CRD system flow control valve maintains the required drive water pressure. The licensee confirmed that the pressure above the core plate increases slightly (approximately 1 psi for EPU) and that, based on operating data, the CRD system flow control valve does not operate near full-open position. It is approximately 50 percent open at CLTP. The licensee concluded that the valve will maintain the required system pressure.

Control Rod Drive Cooling

The increase in reactor power at the EPU operating condition results in a **[[**

]]. The automatic operation of the system flow control valve maintains the required cooling water flow rate, and the CRD cooling function should not be affected. Regardless, the normal CRD cooling function is an operational consideration and not a safety-related function.

The licensee stated that the CRD system flow control valve maintains the required cooling water flow rate. The licensee confirmed that the **[[**

]] and that, based on operating data, the CRD system flow control valve does not operate near full-open position. It is approximately 50 percent open at CLTP. The licensee concluded that the valve will maintain the required system pressure.

Control Rod Drive Integrity Assessment

GGNS indicated that the postulated abnormal operating condition for the CRD design assumes a failure of the CRD System pressure-regulating valve that applies the maximum pump discharge pressure to the CRD mechanism internal components. The postulated abnormal pressure bounds the ASME reactor overpressure limit. **[[**

]]. Therefore, the NRC staff concludes that the maximum calculated stress for the limiting CRD mechanism component is not affected by the EPU.

<u>Conclusion</u>

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the functional design of the CRD system. The NRC staff concludes that the licensee adequately accounted for the impacts of the proposed EPU on the system and demonstrated that the system's ability to effect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents will be maintained following the implementation of the proposed EPU. The NRC staff further concludes that the licensee has demonstrated that sufficient cooling exists to ensure that the system's design basis will continue to be followed upon implementation of the proposed EPU. Based on the above, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of GDC 4, 23, 25, 26, 27, 28, and 29 as well as 10 CFR 50.62(c)(3) following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the functional design of the CRD system.

2.8.4.2 Overpressure Protection during Power Operation

Regulatory Evaluation

Overpressure protection for the RCPB during power operation is provided by relief and safety valves and the RPS. The NRC staff's review covered relief and safety valves on the MSLs and piping from these valves to the suppression pool. The NRC's acceptance criteria are based on (1) GDC 15, "Reactor coolant system design," 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, "Fracture prevention of reactor coolant pressure boundary," insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. SRP Section 5.2.2, "Overpressure Protection" (Reference 62), contains specific review criteria.

Technical Evaluation

Section 5.2.2 of the UFSAR discusses overpressure protection provided by the nuclear pressure relief system. The SRVs provide overpressure protection for the RCPB, preventing failure of the nuclear system pressure boundary and uncontrolled release of fission products.

During a CPPU, the system operating pressure does not change but the steam flow rate increases. The increased steam flow rate associated with the uprated power may increase steam line vibration. The increased core steam generation also causes an increase in the pressurization during some transient events.

The SRV setpoints are established to provide the overpressure protection function while ensuring that there is adequate pressure difference (simmer margin) between the reactor operating pressure and the SRV actuation setpoints to prevent unnecessary SRV actuations during normal plant maneuvers. Since there is no change in dome pressure and simmer margin, no SRV setpoint increase is required and, thus, there is no effect on the SRV opening/closing functionality. GGNS SRV discharge lines are designed and configured so that the discharge backpressure at the valve outlet is not greater than 40 percent of the inlet pressure. The valve design allows for them to achieve sonic (choked) flow conditions through the valve up to the 40 percent backpressure ratio. The backpressure to inlet pressure ratio is determined by discharge line geometry which does not change with EPU. The NRC staff accepts the licensee's assessment that the SRVs will have sufficient capacity to handle the increased steam flow associated with operation at the EPU power level.

The design pressure of the reactor vessel and the RCPB remains at 1250 psig. The ASME Code-allowable peak pressure for the reactor vessel and the RCPB is 1375 psig (110 percent of the design pressure of 1250 psig), which is the acceptance limit for pressurization events. The licensee determined the MSIV closure with scram on high flux (MSIVF) is the limiting overpressure event. The analyses assumed 102 percent of EPU RTP and an initial dome pressure of 1060 psia. The analyses also assume seven SRVs out of service (OOS). The MSIVF event resulted in a maximum reactor dome pressure of 1302 psig and a 1334 psig peak pressure in the bottom of the vessel. The peak vessel pressure of 1334 psig remains below the

ASME limit of 1375 psig and the maximum calculated dome pressure of 1302 psig remains below the TS safety limit of 1325 psig. The licensee used NRC approved code ODYN to perform the evaluation.

Conclusion

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

2.8.4.3 Reactor Core Isolation Cooling System

Regulatory Evaluation

The reactor core isolation cooling (RCIC) system serves as a standby source of cooling water to provide a limited decay heat removal (DHR) capability whenever the main feedwater (feedwater) system is isolated from the reactor vessel (RV). In addition, the RCIC system may provide DHR necessary for coping with a station blackout (SBO). The water supply for the RCIC system comes from the CST, with a secondary supply from the suppression pool. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the system.

The NRC's acceptance criteria are based on (1) GDC 4, "Environmental and dynamic effects design bases," insofar as it requires that SSCs important to safety be protected against dynamic effects, (2) 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 demonstrated that sharing will not impair their ability to perform their safety function, (3) GDC 29, "Protection against anticipated operational occurrences," insofar as it requires that the protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in the event of AOOs, (4) GDC 33, "Reactor coolant makeup," insofar as it requires that a system to provide reactor coolant makeup for protection against small breaks in the RCPB be provided so that the fuel design limits are not exceeded, (5) GDC 34, "Residual heat removal," insofar as it requires that a residual heat removal system be provided to transfer fission product decay heat and other residual heat from the reactor core at a rate such that SAFDLs and the design conditions of the RCPB are not exceeded, (6) GDC 54, "Piping systems penetrating containment," insofar as it requires that piping systems penetrating containment be designed with the ability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits, and (7) 10 CFR 50.63, "Loss of all alternating current power," insofar as it requires that the plant withstand and recover from a SBO of a specified duration. SRP Section 5.4.6, "Reactor Core Isolation Cooling System (BWR)" (Reference 62), contains specific review criteria.

Technical Evaluation

The RCIC system is required to maintain sufficient water inventory in the reactor to permit adequate core cooling following a reactor vessel isolation event accompanied by loss of flow from the feedwater system. The system must inject at a rate to maintain reactor vessel water level above top of active fuel (TAF) at EPU conditions over a wide range of operating pressures.

The maximum injection pressure for RCIC is conservatively based on the upper analytical set point for the lowest available group of SRVs operating in relief mode. For the GGNS EPU, there is no change to the reactor dome pressure (1040 psia) and therefore no change to the SRV set points and so there is no change to the maximum reactor pressure for RCIC system operation. The GGNS RCIC pump is adequate to support EPU. Since the performance requirements of the RCIC system are satisfied at EPU conditions, the licensee has satisfied the GDC that require (1) a supply of reactor coolant makeup for protection against small breaks in the RCPB to assure fuel design limits are not exceeded and (2) residual heat removal to transfer fission product decay heat and other residual heat away from the reactor core at a rate such that SAFDLs and design conditions of the RCPB are not exceeded.

The licensee stated that at EPU operation the NPSH available for the RCIC pump does not change since there is no change to the maximum rated pump speed or the required pump flow rate. The EPU also does not affect the RCIC system ability to transfer suction to suppression pool or CST.

The NRC staff analyzed the licensee discussion of the loss of feedwater (LOFW) transient (Section 2.8.5.2.3) as well as the SBO event (Section 2.3.5). The licensee evaluated conservatively the pressure performance requirements of the RCIC system, and no RCIC system power dependent function or operating requirements (flows, pressure, temperature, and NPSH) are added or changed from the original design or licensing bases. The NRC staff concludes that RCIC will continue to meet the NRC's acceptance criteria as described in the Regulatory Evaluation above.

Conclusion

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the ability of the RCIC system to provide DHR following an isolation of main feedwater event and an SBO event and to provide makeup to the core following a small break in the RCPB. The NRC staff concludes that the licensee adequately accounted for the effects of the proposed EPU on these events and demonstrated that the RCIC system will continue to provide sufficient DHR and makeup for the events following implementation of the proposed EPU. Based on the above, the NRC staff concludes that the RCIC system will continue to meet the requirements of GDC 4, 29, 33, 34, and 54 and 10 CFR 50.63 following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the RCIC system.

2.8.4.4 Residual Heat Removal System

Regulatory Evaluation

The RHR system is used to cool down the RCS following shutdown. The RHR system is a low pressure (LP) system which takes over the shutdown cooling function when the RCS pressure and temperature are 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 to provide DHR.

The NRC's acceptance criteria are based on (1) GDC 4, "Environmental and dynamic effects design bases," insofar as it requires that SSCs important to safety be protected against dynamic effects, (2) 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 (3) GDC 34, "Residual heat removal," which specifies requirements for the RHR system.

Technical Evaluation

At GGNS, the RHR system is designed to operate in the low pressure coolant injection (LPCI) mode, shutdown cooling (SDC) mode, suppression pool cooling (SPC) mode, containment spray cooling (CSC) mode, and fuel pool cooling (FPC) assist. The RHR system is designed to restore and maintain the reactor coolant inventory following a LOCA and remove reactor decay heat following reactor shutdown for normal, transient, and accident conditions. The EPU effect on the RHR system is a result of the higher decay heat in the core corresponding to the uprated power and the increased amount of reactor heat discharged into the containment during a LOCA. LPCI mode is evaluated in Section 2.8.5.6.2 of this SE.

The SPC mode of RHR is manually initiated following isolation transients and a postulated LOCA to maintain the containment pressure and suppression pool temperature within design limits. The CSC mode reduces containment temperature and pressure during an accident. The effect of the CSC and the suppression pool are discussed in Section 2.6 of the SE. The suppression pool temperatures stay within RHR design limits. The containment pressure for EPU events increased but remains within equipment design parameters.

The EPU increases the reactor decay heat, which means a longer time is needed to cool down the reactor. The SDC mode of RHR is designed to remove the sensible and decay heat from the reactor primary system during a normal reactor shutdown. The SDC analysis for the EPU determined that it would take approximately 16.4 hours to cool down the reactor to 125 °F. The time is increased from the current 10.6 hours but still remains under the UFSAR Section 5.4.7.1.1.1 time criterion of 20 hours. This function is a non-safety mode and has no effect on the design operating margins so no change to the RHR system is required.

The FPC assist mode of RHR is designed to use the RHR system to remove heat from the SFP when the heat load exceeds the heat removal capability of the fuel pool cooling and cleanup system (FPCCS). Analysis in Section 2.5.3.1 shows the EPU does not affect the ability of the system to perform its function.

The feedwater leakage control (FWLC) system is designed to minimize the release of fission products that could bypass the standby gas treatment system (SGTS) during a LOCA. The RHR jockey pumps can be used to fill the feedwater line volume between the containment isolation valves. The licensee stated that the peak containment temperature and pressure are within design limits and no changes are necessary to maintain the FWLC function.

Conclusion

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the RHR system. The NRC staff concludes that the licensee adequately accounted for the effects of the proposed EPU on the system and demonstrated that the RHR system will maintain its ability to cool the RCS following shutdown and provide DHR. Based on this finding, the NRC staff concludes that the RHR system will continue to meet the requirements of GDC 4 and 34 following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the RHR system.

2.8.4.5 Standby Liquid Control System

Regulatory Evaluation

The standby liquid control system (SLCS) provides backup capability for reactivity control independent of the control rod system. The SLCS functions by injecting a boron solution into the reactor to effect shutdown. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the system to deliver the required amount of boron solution into the reactor. The NRC's acceptance criteria are based on (1) GDC 26, "Reactivity control system redundancy and capability," insofar as it requires that two independent reactivity control systems of different design principles be provided, and that one of the systems be capable of holding the system subcritical in the cold condition, (2) GDC 27, "Combined reactivity control systems capability," insofar as it requires that the reactivity control systems have a combined capability, in conjunction with poison addition by the ECCS, to reliably control reactivity changes under postulated accident conditions, and (3) paragraph (c)(4) of 10 CFR 50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants," insofar as it requires that the SLCS be capable of reliably injecting a borated water solution into the RPV at a boron concentration, boron enrichment, and flow rate that provides a set level of reactivity control. SRP Section 9.3.5, "Standby Liquid Control System (BWR)" (Reference 62), contains specific review criteria, and other guidance appears in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

The SLCS is designed to shut down the reactor from rated power conditions to cold shutdown in the postulated situation that some or all of the control rods cannot be inserted. The manually operated system pumps a sodium pentaborate solution into the vessel to provide neutron absorption and achieve a subcritical reactor condition. The SLCS is designed to inject over a wide range of reactor operating pressures.

The CLTR provides for a generic disposition of the SLCS. The CLTR states, the effect of EPU on system performance and hardware is increased heat load and potential increase in transient reactor pressure. The SLCS is designed for injection at a maximum reactor pressure equal to the upper allowable value (AV) for the lowest group of SRVs operating in safety relief mode. The licensee nominal reactor dome pressure and the SRV setpoints are unchanged for EPU. The CLTR also states, changes in fuel design for EPU may require modifications to the SLCS as a result of the increase in the suppression pool temperature for the limiting ATWS event. The licensee boron injection rate requirement to maintain peak suppression pool water temperature limits, following the limiting ATWS event with SLCS injection, is not increased for EPU.

The licensee stated, and the NRC staff concludes, that the ability of the boron solution to shut down the reactor is not directly related to core thermal power. In fact, the requirements of 10 CFR 50.62(c)(4) are prescriptive rather than hardware specific.

Based on the above, the NRC staff concludes that the SLCS will perform acceptably in EPU operation.

Conclusion

The NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the SLCS and concludes that the licensee adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system will continue to provide the function of reactivity control independent of the control rod system following the implementation of the proposed EPU. Based on this finding, the NRC staff concludes that the SLCS will continue to meet the requirements of GDC 26 and 27 as well as 10 CFR 50.62(c)(4) following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the SLCS.

2.8.5 Accident and Transient Analyses

AOOs are abnormal transients which are expected to occur one or more times in the life of a plant. These events are initiated by a malfunction, a single failure of equipment, or a personnel error. The applicable acceptance criteria for the AOOs are based on GDC 10, "Reactor design," GDC 15, "Reactor coolant system design," GDC 20, "Protection system functions," GDC 25, "Protection system requirements for reactivity control malfunctions," GDC 26, "Reactivity control system redundancy and capability," GDC 27, "Combined reactivity control systems capability," GDC 28, "Reactivity limits," GDC 31, "Fracture prevention of reactor coolant pressure boundary," and GDC 35, "Emergency core cooling."

DBAs are not expected to occur but are postulated to occur because their consequences could potentially release significant amounts of radioactive material. They are analyzed to determine the extent of fuel damage expected and to assure that the radiological dose is maintained within guidelines of 10 CFR 50.34, "Content of applications; technical information." The applicable acceptance criteria for DBAs such as LOCAs are based on 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," Appendix K, "ECCS Evaluation Models," to 10 CFR Part 50, and GDCs 4, 27, and 35.

The SRP provides further guidelines for evaluation (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 critical power ratio (CPR) remains above the minimum critical power ratio (MCPR) safety limit, and (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. Based on the ANS standards, the reviewer needs to ensure that there is no possibility of initiating a postulated accident with the frequency of occurrence of an AOO.

The GGNS UFSAR Section 15 describes a wide range of potentially limiting events. A potentially limiting event is an event or an accident that has the potential to affect the core operating and safety limits. The plant's response to the limiting transients is analyzed at each reload cycle and is used to establish thermal limits. In this section, the analyses include AOOs in the following categories: (1) a decrease in core coolant temperature, (2) an increase in reactor pressure, (3) a decrease in reactor coolant flow rate, (4) reactivity and power distribution anomalies, (5) an increase in reactor coolant inventory, and (6) a decrease in reactor coolant inventory. UFSAR Section 15 also evaluates the following DBA events: Control Rod Drop Accident (CRDA), LOCA, Refueling Accident, and Main Steam Line Break Accident. Radiological consequences of DBAs are also addressed.

The NRC approved generic guidelines for EPU application identified the set of limiting transients to be evaluated in each event category for the EPU core in **[[**
]]. Among the listed events in ELTR1, the following transients were evaluated in the GGNS PUSAR:

Fuel thermal margin events:

Generator Load Rejection with Steam Bypass Failure (LRNBP) ------------ Most limiting
Turbine Trip with Steam Bypass Failure (TTNBP)
Feedwater Controller Failure Maximum Demand (FWCF)
Pressure Regulator Failure Downscale (PRFD)
Loss of Feedwater Heating (LFWH)
Rod Withdrawal Error (RWE)
Slow Recirculation Increase (SRI)
Fast Recirculation Increase (FRI)
Load Rejection with Bypass (LRWBP)
Main Steam Isolation Valve Closure with Direct Scram - with All Valves (MSIVA)
Main Steam Isolation Valve Closure with Direct Scram - with One Valve (MSIVO)

Limiting transient overpressure events:

Main Steam Isolation Valve Closure with Scram on High Flux (MSIVF) ---- Most limiting
Turbine Trip with Bypass Failure and Scram on High Flux (TTNBPF)

Limiting loss of water level transients:

Loss of Feedwater (LOFW) --- Most limiting
Loss of One Feedwater Pump (LOOFP)

Inadvertent High Pressure Coolant Injection (HPCI) Start listed in [[ ]] was not analyzed because of the following justifications. Inadvertent HPCI Start event for GGNS was not analyzed because the plant does not have HPCI. GGNS is a BWR/6 design with High Pressure Coolant Spray (HPCS). The Inadvertent HPCS Start is considered not limiting and was not analyzed, as discussed in Section 2.8.5.5 of this SE.

It is shown by precedent power uprate applications that the characteristics of the transient events that determine the operating limits do not change significantly when reactor power is increased up to 120 percent at constant pressure power uprate operation. Since the "actual" core of the first EPU cycle is not designed at this time, the analysis to support the proposed EPU application used an "equilibrium" core comprised of GNF2 fuel design. The results of the limiting safety margin analyses depend upon the core design, loading pattern, etc., and, therefore, the "actual" EPU core will be used when performing the reload analysis. Deviation, if any, of limiting transient sets using the actual core will be acceptable, provided justifications are given.

GGNS EPU transient and accident analyses used the NRC staff approved methods. The GEMINI methodology was employed. The fuel thermal margin (MCPR) events were analyzed at 100 percent power level, and non-MCPR events were analyzed at 102 percent power level. The RPV dome pressure was assumed to be 1040 psia and 13 (out of a total of 20) SRVs were assumed to be operable in the analysis.

Most of the system transients were evaluated with ODYN code combined with PANACEA, ISCOR and SAFER codes. The ODYN code is used to predict reactor key parameter responses including power, pressure, temperature, void, water level and core flow.

A reliable reactor protection system is provided for GGNS. Two independent reactivity control systems: control rod drive (CRD) system and standby liquid control system (SLCS) are installed. The capability to bring the core to subcritical state under any conditions is maintained during EPU operation. Thus GDC 20 and GDC 26 are ensured.

In summary, the transients analyzed with approved methodology in PUSAR can be categorized into three groups: (1) fuel thermal margin events; (2) limiting transient overpressure event; and (3) limiting loss of water level transients. Based on the results provided in Table 2.8-5 of the PUSAR (Reference 57), LRNBP (Generator Load Rejection with Steam Bypass Failure) is the most limiting transient (with delta-CPR equal to 0.23) in Fuel thermal margin event category, and is used to establish operating limit MCPR (OLMCPR). In terms of fuel thermal protection, this group of transients is acceptable. MSIVF (Main Steam Isolation Valve Closure with Scram on High Flux) is the most limiting event in overpressure transient category. The results provided in Section 2.8.4.2 of the PUSAR show a maximum reactor pressure of 1,334 psig (ASME limit is 1,375 psig). Thus this category of transients is acceptable. LOFW (Loss of Feedwater) is the most limiting event in the loss of water level transient category. The results of the LOFW analysis for GGNS show that the minimum water level inside the shroud is 50 inches above the TAF at EPU conditions. Thus no core uncover is expected and thus this group of transients is also acceptable.

2.8.5.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Main Steam Relief or Safety Valve

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) postulated initial core and reactor conditions; (2) methods of thermal and hydraulic analyses; (3) the sequence of events; (4) assumed reactions of reactor system components; (5) functional and operational characteristics of the RPS; (6) operator actions; and (7) the results of the transient analyses. The regulatory acceptance criteria are based on: (1) GDC 10, "Reactor design," insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations including AOOs; (2) GDC 15, "Reactor coolant system design," 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; (3) GDC 20, "Protection system functions," insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; and (4) GDC 26, "Reactivity control system redundancy and capability," insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.1.1 - 15.1.4, "Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

Transients in this category include Loss of feedwater heating (LFWH), Feedwater Controller Failure Maximum Demand (FWCF), Increase in Steam Flow, and Inadvertent Opening of a Main Steam Relief or Safety Valve. A feedwater heater can be lost in case (1) the steam extraction line to the heater is shut, causing the heat supply to the heater to be removed, producing gradual cooling of the feedwater heater, and (2) a bypass line opens so that the feedwater flow is bypassed instead of running through the heater. In either case, the reactor vessel receives cooler feedwater which produces an increase in core inlet subcooling. Due to negative moderator temperature feedback, it results in an increase of reactivity and power. LFWH event is a slow transient and a scram on high APRM thermal power may occur. FWCF event causes increase in feedwater flow, and therefore results in core power to rise.

LFWH and FWCF events are discussed in PUSAR Section 2.8.5.1. The LFWH event was performed with the NRC approved methods described in GESTAR II (Reference 154). The computer code used to evaluate the LFWH event was PANACEA. Calculated delta-CPR values are 0.12 and 0.21 for LFWH and FWCF events, respectively (PUSAR Table 2.8-5), which are bounded by other transients in terms of fuel thermal margin (e.g. LRNBP (delta-CPR of 0.23)).

The pressurization effect of the transients belonging to this category is well bounded by other pressurization transients (e.g. MSIVF).

The Increase in Steam Flow event and the Inadvertent Opening of a Safety Relief Valve event are not listed in Table E-1 of ELTR1 to be analyzed for EPU. The Increase in Steam Flow event (for GEH BWRs, this is the Pressure Regulator Failure - Open (PRFO)) is not included in the list of transients because it is bounded by other events. This event results in a low pressure isolation signal to the MSIVs. The initial power decrease and MCPR increase at the beginning of this event result in the event MCPR is bounded by either the LFWH or FWCF. The Inadvertent Opening of a Safety Relief Valve event is not included in the list of transients because it is not limiting for any GEH BWR with respect to MCPR or fuel duty as the event results in a small power change. In addition, the steam pressure regulator stays in service during this event to control reactor pressure.

Because GDC 10, 15, 20, and 26 are met, this group of transients is acceptable.

Table 2.8.5-1. Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Main Steam Relief or Safety Valve Evaluation

FUEL THERMAL MARGIN EVENTS	DISPOSITION
Loss of Feedwater Heating (LFWH)	Analyzed - bounded by LRNBP for MCPR
Feedwater Controller Failure Max Demand (FWCF)	Analyzed - bounded by LRNBP for MCPR
Increase in Steam Flow	Non Limiting - not analyzed
Inadvertent Opening of a Safety Relief Valve	Non Limiting - not analyzed

Conclusion

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

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; Closure of Main Steam Isolation Valve; and Steam Pressure Regulator Failure (Closed)

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 regulatory acceptance criteria are based on: (1) GDC 10, "Reactor design," insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, "Reactor coolant system design," insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, "Reactivity control system redundancy and capability," insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.1 – 15.2.5, "Loss of External Load; Turbine Trip; Loss of Condenser Vacuum; Closure of Main Steam Isolation Valve (BWR); and Steam Pressure Regulator Failure (Closed)" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

This category of transients includes Generator Load Rejection with Steam Bypass Failure (LRNBP), Turbine Trip with Steam Bypass Failure (TTNBP), Loss of Condenser Vacuum (LOCV), Main Steam Isolation Valve Closure with Direct Scram - with All Valves (MSIVA), Main Steam Isolation Valve Closure with Direct Scram - with One Valve (MSIVO), and Steam Pressure Regulator Failure – Downscale (Closed) (PRFD). The LOCV event is not included in the list of transients because it is bounded by other events. For the LOCV event, the steam bypass valves are available for a short period of time and therefore this event is bounded by TTNBP.

Generic analyses performed in ELTR1 indicated that Main Steam Isolation Valve Closure with Scram on High Flux (MSIVF) event is the most limiting transient for pressurization events. The MSIVF was analyzed in PUSAR Section 2.8.4.2. The results show a peak reactor bottom pressure of 1,334 psig. It is within the acceptance criterion of 1375 psig (ASME 110 percent of design pressure 1250 psig). Hence, RCPB design limit is not exceeded. This event is considered as infrequent event instead of AOO. Thus MSIVF is not used to establish thermal margin. Turbine Trip with Bypass Failure and Scram on High Flux (TTNBPF) is determined to be generically non-limiting from the standpoint of over pressurization compared to the MSIVF due to the differences in the dynamic response and the increased steam volume associated with a turbine trip stop valve closure. A TTNBPF analysis was performed for GGNS EPU and the peak reactor pressure as measured in the steam dome was confirmed to be approximately 40 psi lower than the MSIVF event.

Other transients in this group are evaluated to ensure specified acceptable fuel design limits (SAFDLs) are not exceeded through establishing operating limit of MCPR. The LRNBP event was analyzed. In this event, a loss of generator electrical load from high power conditions initiates main turbine control valve fast closure. Turbine control valve closure is sensed by the reactor protection system, and it activates the reactor scram. The results of this event show a delta-CPR of 0.23 (PUSAR Table 2.8-5). This transient is the limiting event for MCPR among the analyzed set in PUSAR Table 2.8-5. This is used to establish OLMCPR for fuel thermal limit protection. As long as OLMCPR is not exceeded, SAFDL are assured. The TTNBP event was also analyzed. A variety of turbine or nuclear system malfunctions could initiate a turbine trip. Once initiated, all of the main turbine stop valves close within about 0.01 second. Analysis of TTNBP shows delta-CPR of 0.22 (PUSAR Table 2.8-5), which is bounded by the LRNBP event.

Analysis of the PRFD event shows delta-CPR to be equal to 0.13 (PUSAR Table 2.8-5), which is bounded by the LRNBP event.

The MSIVA and the MSIVO events were also analyzed. They show delta-CPR of 0.02 and 0.07, respectively, and, therefore, these events are well bounded by the LRNBP event. Since GDCs 10, 15, and 26 are met, this group of transients is acceptable.

Table 2.8.5-2. Loss of External Load; Turbine Trip; Loss of Condenser Vacuum; Closure of Main Steam Isolation Valve; and Steam Pressure Regulator Failure (Closed) Evaluation

FUEL THERMAL MARGIN EVENTS	DISPOSITION
Generator Load Rejection with Steam Bypass Failure (LRNBP)	Analyzed - most limiting event for MCPR
Turbine Trip with Steam Bypass Failure (TTNBP)	Analyzed - bounded by LRNBP for MCPR
Pressure Regulator Failure Downscale (PRFD)	Analyzed - bounded by LRNBP for MCPR
Main Steam Isolation Valve Closure with Direct Scram - with All Valves, with One Valve	Analyzed - bounded by LRNBP for MCPR
Loss of Condenser Vacuum	Non Limiting - not analyzed

TRANSIENT OVERPRESSURE EVENTS	DISPOSITION
Main Steam Isolation Valve Closure with Scram on High Flux (MSIVF)	Analyzed - most limiting event for reactor overpressure
Turbine Trip with Bypass Failure and Scram on High Flux (TTNBPF)	Analyzed – bounded by MSIVF for reactor overpressure

Conclusion

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

2.8.5.2.2 Loss of Nonemergency AC Power to the Station Auxiliaries

Regulatory Evaluation

The loss of nonemergency ac power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant circulation pumps. This causes a flow coastdown as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered (1) the sequence of events, (2) the analytical model used for analyses, (3) the values of parameters used in the analytical model, and (4) the results of the transient analyses. The NRC's acceptance criteria are based on (1) GDC 10, "Reactor design," insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, "Reactor coolant system design," insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, "Reactivity control system redundancy and capability," insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.6, "Loss of Nonemergency AC Power to the Station Auxiliaries" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

The reactor is subject to a complex sequence of events when the station loses all auxiliary power. This can occur if all external grid connections are lost or if faults occur in the auxiliary power system itself. The turbine trip with no bypass (TTNBP) event bounds this event because the loss of non-emergency AC power event causes a delayed turbine trip with a recirculation pump trip. The introduced reactivity will be less than regular TTNBP. TTNBP is addressed in Section 2.8.5.2.1 of this SE and is acceptable. Therefore, this event is well bounded by other transients. Also according to ELTR1 evaluation, Loss of Auxiliary Power to the Station Auxiliaries is a non-limiting event for all GE BWRs. This event is not analyzed.

Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of nonemergency ac power to station auxiliaries event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. 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. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the loss of nonemergency ac power to station auxiliaries event.

2.8.5.2.3 Loss of Normal Feedwater Flow

Regulatory Evaluation

A loss of normal feedwater flow could occur from pump failures, valve malfunctions, or a Loss of Offsite Power (LOOP). Loss of Feedwater (LOFW) flow results in an increase in reactor coolant temperature and pressure, and eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a loss of normal feedwater flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient. The NRC staff's review covered: (1) the sequence of events; (2) the analytical model used for analyses; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The regulatory acceptance criteria are based on: (1) GDC 10, "Reactor design" insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, "Reactor coolant system design," insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, "Reactivity control system redundancy and capability," insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.7, "Loss of Normal Feedwater Flow" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

Feedwater control system failure or reactor feedwater pump trip can lead to partial or complete loss of feedwater flow. Loss of feedwater flow results in a situation where the mass of steam leaving the reactor vessel exceeds the mass of water entering the vessel, resulting in a decrease in the coolant inventory available for core cooling. According to ELTR1, Appendix E.2.2, the safety criteria for the loss of feedwater flow event (maintenance of adequate transient core cooling) is met by maintaining the water level (inside the core shroud) above the Top of Active Fuel (TAF).

GGNS performed plant-specific calculation with a representative equilibrium GNF2 core for (a) complete loss of feedwater (LOFW) flow, and (b) loss of one feedwater pump (LOOFP) events, as discussed below.

Loss of Feedwater (LOFW) Flow

Higher decay heat results in a lower reactor water level for loss of water level events. For the LOFW event, adequate transient core cooling is provided by maintaining the water level inside the core shroud above the TAF. A plant-specific analysis was performed for GGNS at EPU conditions. This analysis assumed failure of the HPCS system and used only the RCIC system to restore the reactor water level. Because of the extra decay heat from the EPU, slightly more time is required for the automatic systems to restore water level. Operator action is only needed for long-term plant shutdown. The results of the LOFW analysis for GGNS show that the minimum water level inside the shroud is 50 inches above the TAF at EPU conditions. After the water level is restored, the operator manually controls the water level, reduces reactor pressure, and initiates residual heat removal (RHR) shutdown cooling (SDC). This sequence of events does not require any new operator actions or shorter operator response times. Therefore, the operator actions for an LOFW transient do not significantly change for EPU.

The SAFER04 computer code was used for this transient analysis, which is the same model used in the ECCS LOCA analysis. The reactor is assumed to be at 102 percent of the EPU power level when the LOFW occurs. The initial level in the model is conservatively set at the low-level scram setpoint and reactor feedwater is instantaneously isolated at event initiation. Scram is initiated at the start of the event. The RCIC system is initiated when the level decreases to the low-low level. The MSIV closure initiates when the level decreases to low-low-low level. The RCIC flow to the vessel begins at 60 seconds into the event, minimum level is reached at 622 seconds and level is recovered after that point. Only RCIC flow is credited to recover the reactor water level. There are no additional failures assumed beyond the failure of the HPCS system.

The only other key analysis assumption for the LOFW analysis was the assumed decay heat level of ANS 5.1-1979 with a two-sigma uncertainty. The assumed decay heat level for the EPU analysis was ANS 5.1-1979 decay heat +10 percent, which bounds ANS 5.1-1979 + two sigma. Thus, the key analytical assumptions are the same or conservative relative to the CLB.

This LOFW analysis is performed to demonstrate acceptable RCIC system performance. The design-basis criterion for the RCIC system is confirmed by demonstrating that it is capable of maintaining the water level inside the shroud above the TAF during the LOFW transient. The minimum level is maintained at least 50 inches above the TAF, thereby demonstrating acceptable RCIC system performance. There are no applicable equipment out-of-service (OOS) assumptions for this transient.

An operational requirement is that the RCIC system restores the reactor water level while avoiding automatic depressurization system (ADS) timer initiation and main steam isolation valve closure (MSIVC) activation functions associated with the low-low-low reactor water level setpoint (Level 1). This requirement is intended to avoid unnecessary initiations of safety systems. This requirement is not a safety-related function. The results of the LOFW analysis for GGNS show that the nominal Level 1 setpoint trip is avoided.

The increased decay heat due to EPU operation results in a slower reactor water level recovery compared to CLTP case. The reactor level is automatically maintained above the TAF without any operator actions. The results show that the minimum water level inside the core shroud is 50 inches above the top of the fuel. The core remains covered throughout the transient and hence no cladding failure is expected. Based on the level recovery and RCIC performance, this transient is acceptable under EPU condition.

Loss of One Feedwater Pump

The Loss of One Feedwater Pump event only addresses operational considerations to avoid reactor scram on low reactor water level (Level 3). This requirement is intended to avoid unnecessary reactor shutdowns. The GGNS plant-specific analysis demonstrated that this requirement is satisfied and, therefore, is acceptable.

Table 2.8.5-3. Loss of Normal Feedwater Flow Conclusions

LOSS OF WATER LEVEL EVENTS	DISPOSITION
Loss of Feedwater (LOFW)	Analyzed - most limiting event for minimum water level
Loss of One Feedwater Pump (LOOFP)	Analyzed - bounded by LOFW for water level

Conclusion

The NRC staff has reviewed the licensee's analyses of the loss of normal feedwater flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of the loss of normal feedwater flow. Based on the above, 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. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the loss of normal feedwater flow event.

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

Regulatory Evaluation

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

Including Trip of Pump Motor and Flow Controller Malfunctions" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

The Loss of Forced Reactor Coolant Flow event, including the Trip of Pump Motor and Flow Controller Malfunction events, results in a decrease in reactor core coolant flow rate. As the core flow decreases, additional core void will form and cause a decrease in reactor power through void feedback. The thermal inertia of the fuel will cause thermal power to lag behind the neutron flux and core flow decay. Critical power will reduce due to core flow reduction but the operating power will sustain for a little while. This combination causes the calculated MCPR to decrease to a lower value but not to SLMCPR. The fuel thermal margin is influenced by the rotating inertia of the motor-generator sets since it determines the pump coast down speed.

Generic analyses performed for several BWRs have shown that the events in this category are not limiting and are bounded by other more limiting transients. Therefore, these events are not included in ELTR1 for the EPU evaluation.

Conclusion

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

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

Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of a reactor recirculation pump. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) the postulated initial and long-term core and reactor conditions, (2) the methods of thermal and hydraulic analyses, (3) the sequence of events, (4) the assumed reactions of reactor system components, (5) the functional and operational characteristics of the reactor protection system, (6) operator actions, and (7) the results of the transient analyses. The regulatory acceptance criteria are based on (1) GDC 27, "Combined reactivity control systems capability," insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) GDC 28, "Reactivity limits," insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; and (3) GDC 31, "Fracture prevention of reactor coolant pressure boundary," 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. Specific review criteria are contained in SRP Section 15.3.3 – 15.3.4, "Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

Increased voids in the core during normal uprated power operation require a slight increase in the recirculation drive flow to achieve the same core flow.

Recirculating pump rotor seizure and shaft break are DBAs. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The recirculation pump rotor seizure is more severe because the pump is assumed to stop instantaneously, which results in a quicker reduction in core coolant flow than a recirculation pump shaft break. The sudden decrease in core flow causes a reduction of core heat transfer. However, core uncover is not expected during this accident.

Events in this category, [[

]] Therefore, the Reactor Recirculation Pump Rotor Seizure event is not analyzed for EPU. Thus these accidents are not included in ELTR1 for the EPU evaluation.

SLO is limited to off-rated conditions and is not affected by EPU. SLO operation at GGNS is restricted to a reactor power of 2,705 MWt and a flow of 60.9 Mlb/hr. The analysis for SLO operation is bounded by the Extended Load Line Limit Analysis (ELLLA). SLO operation was unchanged by the MELLLA. SLO operation is unchanged for EPU. The absolute power limit for SLO stays the same, requiring a proportional reduction in the percent of rated power at the uprate power level (i.e., 69.4 percent CLTP or 61.4 percent EPU power).

The Reactor Recirculation Pump Shaft Break event results in a decrease in reactor core coolant flow rate. Events in this category, with the possible exception of SLO pump seizure, are not limiting for any GEH BWR. Thus these accidents are not included in ELTR1 for the EPU evaluation.

Since there are no changes to recirculation pumps, the NRC staff believes that GGNS continues to meet the limits in EPU operation. The NRC staff concludes that the GGNS RCPB is designed with sufficient margin for this non-limiting event and is equipped with effective reactivity control systems. Therefore, GDC 27, 28, and 31 are satisfied in terms of pressurization, temperature and reactivity changes.

Conclusion

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

2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal from subcritical or low power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered (1) the description of the causes of the transient and the transient itself; (2) the initial conditions; (3) the values of reactor parameters used in the analysis; (4) the analytical methods and computer codes used; and (5) the results of the transient analyses. The regulatory acceptance criteria are based on: (1) GDC 10, "Reactor design," insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 20, "Protection system functions," insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC 25, "Protection system requirements for reactivity control malfunctions," insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.1, "Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

The Rod Withdraw Error (RWE) event, a continuous withdrawal of an out-of-sequence rod during a reactor startup from a subcritical or low power condition, is described in GGNS UFSAR Section 15.4.1. Evaluation of the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition event for EPU requires that the expected maximum increase in peak fuel enthalpy during the event be compared against the acceptance criterion 170 cal/gram.

The CLTP Uncontrolled Control Rod Assembly Withdrawal analysis for GGNS is based on NEDO-23842, April 1978 (Reference 173). The GGNS EPU core consists only of GE fuel assemblies and the EPU is limited to 115 percent of OLTP. There is no change to the reactor manual control system or control rod Hydraulic Control Units (HCUs) for EPU. The Rod Control and Information System (RCIS) installed at GGNS provides the same level of protection for GNF2 fuel following EPU provided the power increase is ≤ 20 percent, and the Bank Position Withdrawal System (BPWS) is used at power levels below the lower Low Power Set Point (LPSP) allowable value. Considering these factors, it is expected that no change in peak fuel enthalpy should occur due to EPU because an RWE is a localized low-power event. At the uprated power with the same initial condition, if it is conservatively assumed that a higher fuel enthalpy can be reached due to a higher enrichment or other changes, and that the peak fuel rod enthalpy increases by a factor of 1.2, the RWE peak fuel enthalpy at EPU should not exceed 72 cal/gram. This enthalpy is well within the acceptance criterion 170 cal/gram and is, therefore, acceptable.

Conclusion

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

2.8.5.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal at power may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered (1) the description of the causes of the AOO and the description of the event itself; (2) the initial conditions; (3) the values of reactor parameters used in the analysis; (4) the analytical methods and computer codes used; and (5) the results of the associated analyses. The regulatory acceptance criteria are based on: (1) GDC 10, "Reactor design," insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 20, "Protection system functions," insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC 25, "Protection system requirements for reactivity control malfunctions," insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.2, "Uncontrolled Control Rod Assembly Withdrawal at Power" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

The Uncontrolled Control Rod Assembly Withdrawal at Power (RWE) event is included in the GGNS reload evaluation scope. The RWE event is performed with the NRC approved methods described in GESTAR II (Reference 154). The computer code used to evaluate the RWE event is PANACEA. The transient evaluation and the results of the analysis for EPU are provided in the PUSAR (Table 2.8-5) with a delta-MCPR value of 0.16. The analysis result is bounded by other transients with enough thermal margin and is, therefore, acceptable.

Conclusion

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

2.8.5.4.3 Startup of a Recirculation Loop at an Incorrect Temperature and Flow Controller Malfunction Causing an Increase in Core Flow Rate

Regulatory Evaluation

A startup of an inactive loop transient may result in either an increased core flow (ICF) or the introduction of cooler water into the core. This event causes an increase in core reactivity due to decreased moderator temperature and core void fraction. The NRC staff's review covered (1) the sequence of events; (2) the analytical model; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The regulatory acceptance criteria are based on: (1) GDC 10, "Reactor design," insofar as it requires that the RCS be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC 20, "Protection system functions," insofar as it requires that the protection system be designed to initiate automatically the operation of appropriate systems to ensure that SAFDLs are not exceeded as a result of operational occurrences; (3) GDC 15, "Reactor coolant system design," 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 AOOs; (4) GDC 28, "Reactivity limits," insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core; and (5) GDC 26, "Reactivity control system redundancy and capability," insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.4.4 – 15.4.5, "Startup of an Inactive Loop or Recirculation Loop at an Incorrect Temperature, and Flow Controller Malfunction Causing an Increase in BWR Core Flow Rate" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

Events in this category include recirculation flow controller failure (increasing flow) and start-up of an idle recirculation pump. Start-up of an idle recirculation pump/loop is not listed in **[[** **]]** as a transient analysis to be performed for EPU based on generic evaluation. **[[**

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The Failure of the Recirculation Flow Controller can result in either a slow or fast recirculation increase. The disposition of these events for EPU indicates that **[[**

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The transient analysis results for these events at EPU are provided in the PUSAR (Table 2.8-5). The Fast Recirculation Increase event shows a delta-MCPR equal to 0.07. For the Slow Recirculation Increase event, the OLMCPR is MCPR(f) and thus thermal limits are not violated. Since the delta-MCPR is not limiting compared to other transients and the OLMCPR is bounded, this event is acceptable.

Table 2.8.5-4. Startup of a Recirculation Loop at an Incorrect Temperature and Flow Controller Malfunction Causing an Increase in Core Flow Rate Conclusions

FUEL THERMAL MARGIN EVENTS	DISPOSITION
Start-up of an idle recirculation loop	Non Limiting - not analyzed
Recirculation flow controller failure – slow recirculation increase	Analyzed - bounded by LRNBP for MCPR
Recirculation flow controller failure – fast recirculation increase	Analyzed - bounded by LRNBP for MCPR

Conclusion

The NRC staff has reviewed the licensee's analyses of the increase in core flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on the above, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, 26, and 28 following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the increase in core flow event.

2.8.5.4.4 Spectrum of Rod Drop Accidents

Regulatory Evaluation

Another type of reactivity or power distribution anomaly event is the Control Rod Drop Accident (CRDA). The NRC staff's review covered the occurrences that lead to the accident, safety features designed to limit the amount of reactivity available and the rate at which reactivity can be added to the core, the analytical model used for analyses, and the results of the analyses. The regulatory acceptance criteria are based on GDC 28, "Reactivity limits," insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other reactor vessel internals so as to significantly impair the capability to cool the core. Specific review criteria are contained in SRP Section 15.4.9, "Spectrum of Rod Drop Accidents (BWR)" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

Control Rod Drop Accident (CRDA) is a DBA analyzed in Section 15.4.9 of GGNS UFSAR. This event assumes that a control rod has been fully inserted. The control rod drive is assumed to be uncoupled and withdrawn. The problem rod suddenly becomes free and rapidly falls out of core unto the withdrawn drive coupling. The rate of positive reactivity insertion into reactor core is consistent with the maximum control rod drop velocity. Neutron flux increases and fuels are heated up. Eventually high neutron flux trips the reactor protection system and the reactor scrams.

The spectrum of CRDAs does not change with EPU. The evaluation of a CRDA for the GGNS EPU is a comparison of the expected maximum increase in peak fuel enthalpy with the acceptance criterion 280 cal/gram. The CLTP CRDA for GGNS is based on GE Nuclear Energy's "Banked Position Withdrawal Sequence," NEDO-21231, January 1977 (Reference 174). The GGNS EPU core consists only of GE fuel assemblies and the EPU is limited to 115 percent of OLTP. Control Rod Sequencing at GGNS for CLTP and EPU follows the BPWS. There is no change to the GGNS reactor manual control system or control rod HCUs for EPU. The RCIS installed at GGNS provides the same level of protection for GNF2 fuel following EPU provided the power increase is ≤ 20 percent and BPWS is used at power levels below the lower LPSP allowable value (AV). Considering these factors, no change in peak fuel enthalpy is expected due to EPU because the rod drop accident is a limiting localized low-power event. It is noted in UFSAR Section 4.3.2.3 that the CRDA is inherently self-limiting for core powers above 10 percent of CLTP. If the peak fuel rod enthalpy is conservatively assumed to increase by a factor of 1.2, the CRDA peak fuel enthalpy at EPU will be 162 cal/gram. This enthalpy is well within the acceptance criterion of 280 cal/gram and is acceptable.

Conclusion

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

2.8.5.5 Inadvertent Operation of ECCS or Malfunction that Increases Reactor Coolant Inventory

Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the 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 over-pressurization 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 regulatory acceptance criteria are based on: (1) GDC 10, "Reactor design," insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, "Reactor coolant system design," insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during AOOs; and (3) GDC 26, "Reactivity control system redundancy and capability," insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.5.1 – 15.5.2, "Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

As mentioned earlier in the introduction Section 2.8.5 of this SE, GGNS is a BWR/6 design with HPCS, and the Inadvertent HPCS Start is considered not limiting and was not analyzed. The inadvertent HPCS System Start is confirmed to be a non-limiting transient because introduction of HPCS flow to the upper plenum causes a small depressurization and power decrease. As a result all thermal margins are maintained. Hence, the SAFDL are met and this category of events is acceptable.

Conclusion

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

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of a Pressure Relief Valve

Regulatory Evaluation

The inadvertent opening of a pressure relief valve results in a reactor coolant inventory decrease and a decrease in RCS pressure. The pressure relief valve discharges into the suppression pool. Normally there is no reactor trip. The pressure regulator senses the RCS pressure decrease and partially closes the turbine control valves (TCVs) to stabilize the reactor at a lower pressure. The reactor power settles out at nearly the initial power level. The coolant inventory is maintained by the feedwater (feedwater) control system using water from the condensate storage tank (CST) via the condenser hotwell. 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 regulatory acceptance criteria are based on: (1) GDC 10, "Reactor design," insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, "Reactor coolant system design," insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during AOOs; and (3) GDC 26, "Reactivity control system redundancy and capability," insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.6.1, "Inadvertent Opening of a PWR Pressurizer Pressure Relief Valve or a BWR Pressure Relief Valve" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

Inadvertent opening of a safety/relief valve will cause a decrease in reactor coolant inventory and result in mild depressurization. The pressure regulator senses the reactor pressure decrease and closes the turbine control valve far enough trying to maintain constant reactor vessel pressure. Automatic recirculation flow control system increases the recirculation flow to the maximum to compensate the power reduction. Reactor power settles out at nearly the initial power level. Because the recirculation flow control cannot meet the additional load demand, the pressure regulator set is automatically reduced to a lower limit, and the reactor pressure decreases eventually.

Table E-1 of ELTR1 provides a list of transients that are to be addressed in the power uprate submittal. The Inadvertent Opening of a Pressure Relief Valve event is not listed in Table E-1 of ELTR1 to be analyzed for EPU. Consistent with ELTR1, the Inadvertent Opening of a Safety Valve event is [[

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This event will have a slight effect on fuel thermal margins. Change in surface heat flux is expected to be negligible indicating an insignificant change in the MCPR. According to ELTR1, the bounding event for this category (decrease in reactor coolant inventory) is loss of feed water. Thus, this transient is not listed in the minimum required tests in ELTR1 and hence not analyzed.

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent opening of a pressure relief valve event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the 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. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the inadvertent opening of a pressure relief valve event.

2.8.5.6.2 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 determination of break locations and break sizes; (2) postulated initial conditions; (3) the sequence of events; (4) the analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients; (5) calculations of peak cladding temperature (PCT), total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling; (6) functional and operational characteristics of the reactor protection and ECCS systems; and (7) operator actions. The regulatory acceptance criteria are based on: (1) 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; (2) Appendix K, "ECCS Evaluation

Models," to 10 CFR Part 50, insofar as it establishes required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA; (3) GDC 4, "Environmental and dynamic effects design bases," insofar as it requires that SSCs important to safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer; (4) GDC 27, "Combined reactivity control systems capability," insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (5) GDC 35, "Emergency core cooling," insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented. Specific review criteria are contained in SRP Sections 6.3, "Emergency Core Cooling System," and 15.6.5, "Loss-of-Coolant Accidents Resulting From Spectrum of Postulated Piping Breaks within the Reactor Coolant Pressure Boundary" (Reference 62), and other guidance provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

The emergency core cooling system (ECCS) of GGNS is described in Section 15.6.5 of the GGNS UFSAR. ECCS components are designed to provide protection in the event of a LOCA due to a rupture of the primary system piping. Although DBAs are not expected to occur during the lifetime of a plant, plants are designed and analyzed to ensure that the radiological dose from a DBA will not exceed the 10 CFR Part 100 limits. For a LOCA, 10 CFR 50.46 specifies design acceptance criteria based on (a) the peak cladding temperature (PCT), (b) local cladding oxidation, total hydrogen generation, (c) coolable core geometry, and (d) long-term cooling. The LOCA analysis considers a spectrum of break sizes and locations, including a rapid circumferential rupture of the largest recirculation system pipe. Assuming a single failure of the ECCS, the LOCA analysis identifies the break sizes that most severely challenge the ECCS systems and the primary containment. The maximum average planar linear heat generation rate (MAPLHGR) operating limit is based on the most limiting LOCA analysis, and licensees perform LOCA analyses for each new fuel type to demonstrate that the 10 CFR 50.46 acceptance criteria can be met.

The ECCS for GGNS includes the high pressure core spray (HPCS) system, the low pressure core spray (LPCS) system, the low pressure coolant injection (LPCI) mode of the RHR system, and the automatic depressurization system (ADS).

High Pressure Core Spray (HPCS)

The HPCS system is designed to spray water into the reactor vessel over a wide range of operating pressures and was evaluated in Section 4.3 of ELTR2. The HPCS system provides reactor vessel coolant inventory makeup in the event of a small break LOCA that does not immediately depressurize the reactor vessel and helps to depressurize the reactor vessel. This system also provides spray cooling for long-term core cooling after a LOCA.

The HPCS system also serves as a backup to the RCIC system to provide makeup water in the event of an LOFW flow transient, as discussed in Section 2.8.5.2.3 of this SE. Because the

HPCS injection flow is greater than that of the RCIC system, which results in RPV depressurization, and there is no change to the range of pressures over which HPCS is required for injection, the adequacy of the HPCS system to meet the safety requirement following an LOFW event is demonstrated by the discussion in Section 2.8.5.2.3.

There is no change to the maximum specified reactor pressure for HPCS system operation and no change in the HPCS system performance parameters. The maximum injection pressure for the HPCS system is conservatively based on the upper allowable value for the lowest available group of SRVs. Because the SRV settings and the normal reactor operating pressure remain the same for EPU, the HPCS system operating conditions and operating functions also remain the same.

Therefore, there is no change in the original design pressures or temperatures for the system components. EPU does not change the power required by the pump or the power required by the HPCS diesel generator unit.

Because the maximum normal operating pressure and the SRV setpoints do not change for EPU, the HPCS system performance requirements do not change. Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance" for evaluation) based on the current HPCS capability demonstrate that the system provides adequate core cooling, the NRC staff concludes that the evaluation acceptable, and agree with the licensee's assessment that the HPCS will continue to meet the NRC's acceptance criteria, as outlined in the Regulatory Evaluation section above.

Low Pressure Core Spray (LPCS)

The LPCS system is automatically initiated in the event of a LOCA. When operating in conjunction with other ECCS, the LPCS system is required to provide adequate core cooling for all LOCA events. There is no change in the reactor pressures at which the LPCS is required. The LPCS system sprays water into the reactor vessel after it is depressurized. The primary purpose of the LPCS system is to provide reactor vessel coolant inventory makeup for a large break LOCA and for any small break LOCA after the reactor vessel has depressurized. It also provides long-term core cooling in the event of a LOCA.

The licensee stated that the change in the system operating condition due to EPU for a postulated LOCA does not affect the hardware capabilities of the LPCS system. The generic core spray distribution assessment provided in Section 3.3 of ELTR2 continues to be valid for EPU. Core spray distribution is not directly credited in the short-term cooling for LOCA analyses. This is consistent with ECCS evaluation models specified in Appendix K to 10 CFR 50. Therefore, the convective heat transfer coefficients used during the short-term spray cooling period are the conservative values specified in Appendix K. **[[**

]].

The NRC staff, therefore, concludes that the EPU does not significantly impact operation of the LPCS system. Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance" for evaluation) based on the current LPCS capability demonstrate that the system provides adequate core cooling, the NRC staff concludes that the evaluation acceptable, and agree with the licensee's assessment that the LPCS will continue to meet the NRC's acceptance criteria.

Low Pressure Coolant Injection (LPCI)

The LPCI mode of the RHR system is automatically initiated in the event of a LOCA. The primary purpose of the LPCI mode is to help maintain reactor vessel coolant inventory for a large break LOCA and for any small break LOCA after the reactor vessel has depressurized. The LPCI operating requirements are not affected by EPU and the ECCS performance evaluation demonstrates the adequacy of the LPCI core cooling performance.

Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance" for evaluation) based on the current LPCI capability demonstrate that the system provides adequate core cooling, the NRC staff concludes that the evaluation acceptable, and agrees with the licensee's assessment that the LPCI will continue to meet the NRC's acceptance criteria.

Automatic Depressurization System (ADS)

The ADS evaluation scope is provided in Section 5.6.8 of ELTR1. The ADS uses a number of the SRVs to reduce the reactor pressure following a small break LOCA when it is assumed that the high-pressure systems have failed. After a specified delay, the ADS actuates either on low water level plus high drywell pressure or on sustained low water level alone. This allows the LPCS and LPCI to inject coolant into the reactor vessel. Plant design requires a minimum flow capacity for the SRVs, and that ADS initiates following confirmatory signals and associated time delay(s). The required flow capacity and ability to initiate ADS on appropriate signals are not affected by EPU. The ADS initiation logic and ADS valve control are not affected, and are adequate for EPU conditions. The licensee stated that the ADS at GGNS meets all generic dispositions because the SRV setpoints and functions remain the same, the ADS timers are not changed and the small break LOCA event mitigation is acceptable.

Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance" for evaluation), based on the current ADS capability, demonstrates that the system provides adequate core cooling, the NRC staff concludes that the evaluation acceptable, and agree with the licensee's assessment that the ADS will continue to meet the NRC's acceptance criteria.

The EPU does not affect the protection provided for any of the above mentioned ECCS features (HPCS, LPCS, LPCI, and ADS) against the dynamic effects and missiles that might result from plant equipment failures.

ECCS Performance

The ECCS is designed to provide protection against postulated LOCAs caused by ruptures in the primary system piping. The ECCS performance under all LOCA conditions and the analysis models must satisfy the requirements of 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," and 10 CFR Part 50, Appendix K. The following staff approved codes were used for the equilibrium core LOCA analysis:

SAFER Computer Code

The SAFER code was used to calculate the long-term-thermal-hydraulic behavior of the coolant in the vessel during a LOCA. Some important parameters calculated by SAFER are vessel pressure, vessel water level, and ECCS flow rates. The SAFER code also calculates PCT and local maximum oxidation.

LAMB Computer Code

The LAMB code is used to analyze the short-term thermal-hydraulic behavior of the coolant in the vessel during a postulated LOCA. In particular, LAMB predicts the core flow, core inlet enthalpy, and core pressure during the initial phase of the LOCA event (i.e. the first 5 seconds).

GESTR Computer Code

The GESTR code is used to provide best-estimate predictions of thermal performance of GE nuclear fuel rods experiencing variable power histories. For LOCA analysis, the GESTR code is used to initialize the fuel stored energy and fuel rod fission gas inventory at the onset of a postulated LOCA.

TASC Computer Code

The TASC code has been accepted for transient analysis and LOCA analysis. TASC is a functional replacement of the SCAT code. TASC is an improved version of the NRC approved SCAT code, with the added capability to model advanced fuel features (partial length rods and new critical power correlation). TASC is a detailed model of an isolated fuel channel. It is used to predict the time to boiling transition for a large-break LOCA. This value is used in subsequent codes to turn off nucleate boiling heat transfer models and turn on transition boiling models. In the EPU approach, the LOCA analysis description is based on a limited number of break analyses (one large break and a spectrum of breaks for the small break analyses) instead of the complete set of break-spectrum analyses.

The EPU approach with limited break analyses is acceptable for the following reasons:

a) The NRC staff evaluations of several requests for stretch power increase and extended power uprate at BWRs have shown that the change of PCT for power uprates is not significant. The maximum increase in the PCT was small, and was well within the acceptance criteria of 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors." Since there is an insignificant change in PCT, an EPU has a negligible effect on the adders used to determine the licensing basis PCT.

b) The ECCS performance characteristics and basic break spectrum response are not affected by an EPU.

c) The limiting break sizes are well known and have been shown not to be a function of reactor power level.

d) The analyses assume the hot bundle continues to operate at thermal limits (MCPR, MAPLHGR, and LHGR) which are not changed by the EPU.

e) The PCT for the limiting large-break LOCA is determined primarily by the hot bundle power, which is expected to increase by a small amount with power uprate.

f) The reload evaluation confirms that the MAPLHGR for each fuel type in the specific reload core is bounded by the MAPLHGR used in the ECCS-LOCA performance analysis.

g) If the plant is MAPLHGR-limited or if the LOCA analysis results are at (or above) the acceptance criteria limits, a detailed plant-specific analysis for the licensing basis PCT will be performed.

The LOCA analysis for EPU builds on the existing SAFER/GESTR LOCA analyses for a plant. The NRC staff evaluations of past EPU at BWRs have shown that the basic break spectrum is not affected by EPU and that EPU is expected to have insignificant effect on the licensing basis PCT. A limited set of analyses needs to be performed to determine the impact of EPU. Because the EPU approach has only a small effect on PCT, the limiting single failure is not expected to change for EPU conditions in a plant. The licensing basis PCT is based on the Appendix K PCT. The effect of EPU on the licensing basis PCT will be based on the delta PCT change from the large break and small break evaluation such that the licensing basis PCT is maximized. Use of the most limiting of the nominal or Appendix K PCT changes for the licensing basis PCT will ensure continued compliance with the requirements for the SAFER/GESTR LOCA application methodology as approved by the NRC.

The Licensing Basis PCT is determined based on the calculated nominal PCT plus an "adder" to account for uncertainties. The adder is derived from calculations that are in conformance with the requirements of 10 CFR 50 Appendix K

Based on the licensee's calculations using GNF2 equilibrium core for GGNS EPU, the basic break spectrum response is not affected by EPU. There are two limiting points on the break spectrum: the full sized recirculation suction line break (RSLB) and the worst small break under the HPCS-Diesel Generator failure scenario (limiting single failure). This is unchanged from the current CLTP Licensing Basis PCT. Consistent with Limitation and Condition 9.7 of the Methods LTR SE (Reference 155), both top and mid-peaked power shapes were considered for both large and small break LOCA. **[[**

]] The Appendix K results demonstrate that the limiting LOCA is the DBA RSLB under the limiting single failure of HPCS-Diesel Generator. **[[**

]]. The results of the LOCA analyses are provided in Table 2.8-7 of the PUSAR (Reference 57). The calculated results show significant margin to the licensing limit of 2200 °F.

Restrictions imposed by the NRC on Upper Bound PCT have been removed for GGNS (see NEDE-23785P-A; Reference 175). The Upper Bound PCT has been shown to be bounded by the Licensing Basis PCT, consistent with the previous evaluations (see GEH GNF2 ECCS-LOCA Evaluation (Reference 176) and GE14 ECCS LOCA Evaluation (Reference 177).

The PCT for the limiting large break LOCA is determined primarily by the hot bundle power, which is expected to increase by a small amount with EPU, because the additional core power for EPU is obtained by raising the average bundle power for constant pressure power uprate in BWRs. The current peak bundle power for CLTP (previous Cycle 17 and current Cycle 18) is approximately 7.4 MW and the expected peak bundle power for EPU is projected to be approximately 7.8 MW. In the GGNS analysis, the hot bundle is assumed to be operating at thermal limits (MCPR, MAPLHGR, and LHGR), and these limits are not changed for EPU. Comparison of the GGNS PCT results for CLTP and EPU indicate an insignificant change (<20 °F), and therefore large break LOCA has a negligible effect on compliance with the other acceptance criteria of 10 CFR 50.46 (local cladding oxidation, core-wide metal-water reaction, coolable geometry and long-term cooling). Long-term cooling is assured when the core remains flooded to the jet pump top elevation and when a core spray system is operating. The local fuel conditions are not significantly changed with EPU, because the hot bundle operation is still constrained by the same operating thermal limits. Because EPU has such a small effect on the GGNS large break PCT, the system response over the large break spectrum is not affected. These will be reconfirmed by the licensee for the cycle-specific core, and the results will be documented in the SRLR for the cycle. The NRC staff concludes that this acceptable.

For GGNS, the indicated decay heat for EPU is higher and results in a longer ADS blowdown and a higher PCT for the small break LOCA Appendix K case. Previous analyses (References 176 and 177) demonstrate that GGNS is a large break Appendix K PCT limited plant. The effect of EPU on the calculated small break PCT is acceptable as long as the effect of the results on the Licensing Basis PCT remains below the 10 CFR 50.46 limits. The current TS values for ECCS initiation were used for the analysis, and no changes to these values were required for EPU. Plant-specific analyses demonstrate that there is sufficient ADS capacity, with seven ADS valves in service and one OOS, at EPU conditions, to remain below these limits. Key input parameters to the SAFER/GESTR LOCA evaluation model are provided in Table 2.8-6 of the PUSAR. Input parameters are selected as nominal or representative values. For Appendix K calculation, select inputs are chosen so as to set a bounding condition or to assure conservatism.

For Single Loop Operation (SLO), a multiplier is applied to the two-loop LHGR and MAPLHGR operational limits. The operating conditions for SLO are not changed with EPU; therefore, the current SLO analysis remains acceptable for EPU. At EPU power condition, the MELLLA core flow extends to approximately 92.8 percent of rated core flow. Therefore, the EPU analysis results at rated power and flow are applied to the MELLLA condition. Also, the effect of ICF on PCT is negligible with EPU. Thus the SLO, MELLLA, and ICF domain remain valid with EPU.

Based on licensee's plant-specific LOCA analysis for GGNS EPU condition with equilibrium core, and because the licensee will perform plant cycle-specific evaluations of ECCS-LOCA performance for GGNS first EPU cycle using approved methods, as required in Section 5.2 of ELTR2, the NRC staff agrees with the licensee that the GGNS ECCS-LOCA performance complies with 10 CFR 50.46 and Appendix K requirements.

As confirmatory evaluations, the NRC staff performed audit calculations. The results of the NRC staff's calculations are summarized below:

Staff Confirmatory Calculation of EPU LOCA

The licensing basis PCT was determined based upon the calculated Appendix K PCT at rated core flow, with top-skewed and mid-peaked axial power shapes plus an adder to account for uncertainties. For the EPU, the Licensing Basis appendix K PCT for the large break DBA consisting of a maximum recirculation suction line break with a high pressure core spray-diesel generator failure was calculated to be ≤1690 °F at rated core flow, with transient cladding oxidation not exceeding 2 percent of the original cladding thickness, and hydrogen generation not exceeding 0.1 percent of the core-wide metal-water reaction.

Long-term cooling is assured when the core remains flooded to the jet pump top elevation and when a core spray system is operating.

In addition to the large break LOCA analysis, the small break LOCA response was analyzed and the limiting break was found to be the 0.08 ft^2 recirculation suction line break with the limiting single failure condition consisting of the high pressure core spray-diesel generator failure. The increased decay heat associated with EPU results in a longer ADS blowdown and a higher PCT for the small break LOCA. The PCT for this break was calculated to be 1360 °F. For Appendix K calculations, select inputs are chosen so as to set a bounding condition or to assure conservatism.

It should be mentioned that TRACE audit calculations were not performed for the limiting large and small breaks identified above, since the cladding temperatures were calculated to be well below the 2200 °F limit.

The NRC staff also questioned the Grand Gulf response to a bottom head drain line break (0.049 ft^2). The licensee updated this analysis and **[[**
]], at the power level of 4496.2 MWt and 14.40 kilowatt per foot for the GNF2 GE fuel. As such, this break is bounded by the small break spectrum analysis which includes the bottom drain line break along with the small break in the recirculation line break. Moreover, even though the bottom head drain line break does not include the additional depressurization due to the uncovering of the recirculation line break (permitting vapor to exit the break early in the event), the ADS system in conjunction with the LPCI and LPCS produces a lower, less limiting PCT than that for the limiting 0.08 ft^2 recirculation line break.

<u>Conclusion</u>

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 the above, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 4, 27, and 35, and 10 CFR 50.46 following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the LOCA.

2.8.5.7 Anticipated Transients without Scrams

Regulatory Evaluation

ATWS is defined as an AOO followed by the failure of the reactor trip portion of the protection system specified in GDC 20, "Protection system functions." The regulations in 10 CFR 50.62 require that:

- Each BWR have an alternate rod insertion (ARI) system that is designed to perform its function in a reliable manner and be independent (from the existing reactor trip system) from sensor output to the final actuation device.
- Each BWR have a SLCS with the capability of injecting into the reactor vessel a borated water solution with reactivity control at least equivalent to the control obtained by injecting 86 gpm of a 13 weight percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor vessel. The SLCS initiation must be automatic (for plants granted a construction permit after July 26, 1984).
- Each BWR have equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS.

The NRC staff's review was conducted to ensure that (1) the ability to meet the above requirements; (2) sufficient margin available in the setpoint for the SLCS pump discharge relief valve; and (3) operator actions specified in the EOPs (consistent with the generic emergency procedure guidelines/severe accident guidelines (EPGs/SAGs)), insofar as they apply to the plant design. In addition, the NRC staff reviewed the licensee's ATWS analysis to ensure that (1) the peak vessel bottom pressure is less than the ASME Service Level C limit of 1,500 psig; (2) the PCT is within the 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors," limit of 2,200 °F; (3) the peak suppression pool temperature is less than the design limit; and (4) the peak containment pressure is less than the containment design pressure. The NRC staff also evaluated the potential for thermal-hydraulic instability in conjunction with ATWS events using the methods and criteria approved by the NRC staff, as discussed in Section 2.8.3 of this SE. For this analysis, the NRC staff reviewed the limiting event determination, the sequence of events, the analytical model and its applicability, the values of parameters used in the analytical model, and the results of the analyses. Review guidance is provided in Matrix 8 of RS-001 (Reference 54).

Technical Evaluation

An ATWS event starts when an AOO occurs and yet the control rods could not be inserted to scram the reactor. Due to strong reactivity feedback, reactor power and pressure rise rapidly to reach maximum values and challenge the RCPB and thermal design limits. Eventually the

SLCS will inject boron solution into the core after first SRV opens to relieve reactor pressure. It brings the reactor to subcritical state from the hot full power and remains subcritical until the reactor cools down to the cold-shutdown condition. For every reload, the licensee evaluates how plant modifications, reload core designs, changes in fuel design, and other reactor operating changes that affect the ATWS analysis.

The licensee stated in Section 2.8.5.7 of the PUSAR (Reference 57) that GGNS meets the ATWS mitigation requirements defined in 10 CFR 50.62, because (a) an ARI system is installed, (b) the boron injection capability is equivalent to 86 gpm of 13 weight percent natural boron, and (c) an automatic ATWS-recirculating pump trip (RPT) logic has been installed.

Section L.3 of ELTR1 discusses the ATWS analyses and provides a generic evaluation guideline for the following limiting ATWS events in terms of overpressure and suppression pool cooling: (a) MSIV closure (MSIVC), (b) pressure regulator failure to open (PRFO), (c) loss of offsite power (LOOP), and (d) inadvertent opening of a relief valve (IORV). The licensee reviewed the results of the ATWS analyses considering the limiting cases for RPV overpressure, and for suppression pool temperature and containment pressure. Licensee's previous evaluations considered the four ATWS events. Based on past experience and the generic analyses performed in ELTR2, only two cases needed to be further analyzed for GGNS EPU: (1) MSIVC and (2) PRFO. For GGNS, a LOOP does not result in a reduction in the RHR pool cooling capability relative to these cases. Thus, with the same RHR pool cooling capability, the containment responses for the MSIVC and PRFO cases bound the LOOP case.

The results of the analyzed events are discussed in Sections 2.8.5.7.1 through 2.8.5.7.3 of the PUSAR, and are evaluated below. The EPU ATWS analysis was performed with GNF2 equilibrium core using the NRC approved computer code ODYN, and the results of the analysis are provided in Table 2.8-9 of the PUSAR. The potential for thermal-hydraulic instability in conjunction with ATWS events is discussed in Section 2.8.3.2 of the PUSAR, and was evaluated in Section 2.8.3 of this SE.

The input parameters for GGNS ATWS were provided in Table 2.8-8 of the PUSAR. The SRV capacity and high pressure ATWS-RPT setpoint are not changed. The number of SRVs out-of-service (OOS) was assumed to be five out of 20 at EPU condition. As such, TS 3.4.3 will be revised to increase the total number of required SRVs from 13 to 15 out of 20 to ensure reactor pressure remains below the ASME Service Level C limit of 120 percent of vessel design pressure (120% x 1250 psig = 1500 psig) during the most limiting ATWS event. The May-Witt decay heat model was used in the ATWS analysis. The May-Witt correlation bounds the ANSI/ANS-5.1-1979 + 2 σ decay heat model. Further, the licensee confirmed that all the inputs used for the EPU ATWS analysis were consistent or were more conservative than the guidelines specified in Section L.3.4 of Appendix L to ELTR1.

The licensee confirmed that the SLCS relief valve margin for EPU was 305.9 psi (after taking into account minus 3 percent valve setpoint tolerance limit). A margin of 30 psi from the minimum relief valve setpoint is considered sufficient. Therefore, the NRC staff concludes that sufficient margin remains available in the setpoint for the SLCS pump discharge relief valve, and is acceptable.

The licensee stated that there are no changes to the assumed operator actions for the EPU ATWS analysis. BWROG "Emergency Procedure and Severe Accident Guidelines (EPGs/SAGs)," Revision 2, March 2001 (Reference 178), is currently implemented at GGNS. EPU implementation does not change operator strategy on ATWS level reduction or early boron injection. The changes due to EPU do not require modification of operator instructions.

ATWS (Overpressure)

Higher operating steam flow will result in higher peak vessel pressures. The increased core power and reactor steam flow rates, in conjunction with the SRV capacity and response times, can affect the capability of the SLCS to mitigate the consequences of an ATWS event.

The licensee's overpressure evaluation included a review of the results of the analyses of ATWS events to identify the most limiting RPV overpressure conditions. Two events, MSIVC and PRFO, were further analyzed for GGNS. The limiting ATWS event with respect to RPV overpressure for GGNS is MSIVC. The PRFO event produces the highest peak upper plenum pressure at SLCS initiation (1205 psia).

ATWS (Suppression Pool Temperature)

The increased core power and reactor steam flow rates, in conjunction with the SRV capacity and response times, can affect the capability of the SLCS to mitigate the consequences of an ATWS event. The higher power and decay heat can result in higher suppression pool temperatures. The licensee's suppression pool temperature evaluation included a review of the results of the analyses of ATWS events to identify the most limiting containment response. Two events, MSIVC and PRFO, were further analyzed for GGNS. The limiting ATWS event with respect to containment response for GGNS is PRFO.

ATWS (Peak Cladding Temperature)

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For ATWS events, the acceptance criteria for PCT and local cladding oxidation for ECCS, defined in 10 CFR 50.46 are adopted to ensure an ATWS event does not impede core cooling. Coolable core geometry is assured by meeting the 2200 °F PCT and the 17 percent local cladding oxidation acceptance criteria stated in 10 CFR 50.46.

The ATWS analysis results demonstrate significant margin to the PCT acceptance criteria of 2200 °F. Two events, MSIVC and PRFO, were further analyzed for GGNS. The highest calculated PCT for ATWS events increased from 1509 °F at CLTP to 1560 °F at EPU, which resulted from the PRFO event. Local cladding oxidation is not explicitly analyzed because, with PCT less than 1600 °F, cladding oxidation has been demonstrated to be insignificant compared to the acceptance criteria of 17 percent of cladding thickness. Therefore, the local cladding oxidation for the GGNS ATWS events is qualitatively evaluated to demonstrate compliance with the acceptance criteria of 10 CFR 50.46. Therefore, ATWS (Peak Cladding Temperature) is in compliance with the acceptance criteria of 10 CFR 50.46.

Table 2.8-9 of the PUSAR (Reference 57) lists the key results of ATWS analysis:

Peak vessel bottom pressure 1455 psig < 1500 psig (ASME Service level C)
Peak cladding temperature 1560 °F < 2200 °F (10 CFR 50.46)
Peak suppression pool temperature 165 F < 210 °F (Design limit)
Peak containment pressure 6.4 psig < 15 psig (Design limit)
Local cladding oxidation < 17% (10 CFR 50.46)

The above results show the acceptance criteria are satisfied.

Based on above, the NRC staff accepts the ATWS event based on the following facts (1) GGNS meets ATWS mitigation requirements and (2) The ATWS analysis at EPU condition are based on NRC-approved methods and (3) the results meet the acceptance criterion defined at 10 CFR 50.62 and (4) the EPU implementation has sound operator strategy on ATWS level reduction or early boron injection in the EOP with the BWROG EPGs/SAGs strategy.

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 ARI, SLCS, and recirculation pump trip systems have been installed and that they will continue to meet the requirements of 10 CFR 50.62 and the analysis acceptance criteria following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to ATWS.

2.8.6 Fuel Storage

2.8.6.1 New Fuel Storage

Regulatory Evaluation

Nuclear reactor plants include facilities for the storage of new fuel. The quantity of new fuel to be stored varies from plant to plant, depending upon the specific design of the plant and the individual refueling needs. The NRC staff's review covered the ability of the storage facilities to maintain the new fuel with the required subcritical margin for all normal and credible abnormal storage conditions. The NRC staff's review focused on the effect of EPU operations and changes in fuel design on the analyses for the new fuel storage facilities.

The NRC's acceptance criteria are based on GDC 62, "Prevention of criticality in fuel storage and handling," insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations.

The GGNS TSs require that the k-effective (k_{eff}) of the new fuel storage racks, fully flooded with unborated water, will not exceed 0.95 including an allowance for uncertainties as described in Section 9.1.1 of the UFSAR.

Technical Evaluation

Section 2.8.6.1 of the PUSAR, "New Fuel Storage," references Section 6.3.4 of NEDC-33004P-A, Revision 4, "Licensing Topical Report, Constant Pressure Power Uprate," July 2003 (CLTR) (Reference 55), for the effect of power uprate on the new fuel storage racks. Section 6.3.4 of the CLTR provides brief statements on the effects of decay heat but does not provide any relevant information on fuel storage rack criticality. The NRC staff requested the licensee to provide additional technical justification for the reported new storage rack criticality limits.

By letter dated November 23, 2010 (Reference 3), the licensee submitted GEH topical report NEDC-33621P, "Grand Gulf Nuclear Station, Fuel Storage Criticality Safety Analysis of Spent and New Fuel Storage Racks," November 2010 (Reference 179). NEDC-33621P calculated an in-rack k_{eff} less than 0.9 for the new fuel storage.

Computational Methods and Validation

GEH used two computational methods in the criticality analysis for the new fuel storage rack: a lattice design code TGBLA06 to calculate the in-core k-infinity (k_{∞}) values and a Monte Carlo code MCNP-05P to obtain fuel storage rack k_{eff} values.

TGBLA06 is a two-dimensional lattice design computer program for BWR fuel bundle analysis. It assumes that a lattice is uniform and infinitely long along the axial direction and that the lattice geometry and material are reflecting with respect to the lattice boundary along the transverse directions. The NRC staff has previously reviewed and accepted the use of TGBLA06 for BWR core design calculations, as part of the approval of Amendment 26 of NEDE-24011-P-A, "GESTAR II – Implementing Improved GE Steady-State Methods," for operating BWRs. GEH applied a TGBLA06 cold eigenvalue uncertainty in the criticality analysis for the new fuel storage rack.

MCNP is a generally accepted code used to obtain the fuel storage rack k_{eff} values, and its use is acceptable provided it is properly validated. NEDC-33621P provided information describing the computational method validation. This information included a summary of the critical benchmark experiments and the area of applicability covered by the code validation. The analysis of the new fuel storage rack does not need to consider the depleted fuel composition. The validation also describes the determination of the bias and bias uncertainty. The NRC staff concludes that the bias and bias uncertainty were determined from the validation database using an appropriate statistical treatment that is consistent with NUREG/CR-6698, "Guide for Validation of Nuclear Criticality Safety Calculational Methodology, January 2001 (Reference 180).

Based on the above, the NRC staff concludes that the two computational methods are acceptable for use in the criticality safety analysis.

Fuel Assembly Design

The NRC staff verified that the criticality analysis used the appropriate fuel design data. Section 4 of NEDC-33621P describes fuel design basis, which is the GE14 fuel design, and the fuel criticality model. GEH selected the design basis lattice based on an analysis of GE14 fuel lattice types covering the limiting enrichments and gadolinium loadings at the beginning of life. The lattice corresponding to the highest in-rack k_{eff} was chosen as the design basis lattice. In addition, the appropriate fuel assembly data, including design tolerances, were used in the criticality analysis.

Storage Rack Design

The new fuel storage vault contains 30 rack modules which may contain up to 10 fresh fuel assemblies per rack module. The assemblies are maintained in the castings with a nominal center-to-center spacing within the rack module of 7 inches. The nominal center-to-center spacing between racks is 12 inches. A two-dimensional, infinite model has been defined to describe the new fuel rack storage system in MCNP-05P. The model contains no rack structural materials to limit the number of neutron absorptions by non-fuel components in the system.

Accident Condition

GEH calculated a maximum k_{eff} of the new fuel storage rack of 0.9 for a fully flooded, abnormal condition, which meets the regulatory k_{eff} limit of 0.95. The maximum k_{eff} included allowances for appropriate manufacturing tolerances and other biases and uncertainties to establish a k_{eff} at a 95 percent probability, 95 percent confidence level.

Conclusion

The NRC staff has reviewed the licensee's analysis and dispositions related to the effect of EPU operation on new fuel storage facilities and concludes that the new fuel storage facilities will continue to meet the requirements of GDC 62 and plant-specific licensing basis following implementation of the proposed EPU. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the new fuel storage.

2.8.6.2 Spent Fuel Storage

Regulatory Evaluation

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the spent fuel pool (SFP) and storage racks is to maintain the spent fuel assemblies in a safe and subcritical array during all credible storage conditions and to provide a safe means of loading the assemblies into shipping casks. The NRC staff's review covered the effect of the proposed EPU on the criticality analysis (e.g., reactivity of the spent fuel storage array and boraflex degradation or neutron poison efficacy).

The NRC's acceptance criteria are based on GDC 62, insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations.

The GGNS TSs require that the k_{eff} of the spent fuel storage racks, fully flooded with unborated water, will not exceed 0.95 including an allowance for uncertainties as described in Section 9.1.2 of the UFSAR.

Technical Evaluation

Section 2.8.6.2 of the PUSAR, "Spent Fuel Storage," references Section 6.3.4 of NEDC-33004P-A, Revision 4 (CLTR), for the effect of power uprate on the new fuel storage racks. Section 6.3.4 of the CLTR provides brief statements on the effects of decay heat but does not provide any relevant information on fuel storage rack criticality. By letter dated November 9, 2010 (Reference 116), the NRC staff requested the licensee to provide additional technical justification for the reported new storage rack criticality limits.

By letter dated November 23, 2010 (Reference 3), the licensee submitted NEDC-33621P, "Grand Gulf Nuclear Station, Fuel Storage Criticality Safety Analysis of Spent and New Fuel Storage Racks," November 2010 (Reference 179).

The SFP storage racks at GGNS contain Boraflex as a permanently installed neutron absorber. Boraflex is a silicon rubber product with B4C. The silicon rubber breaks down after achieving a threshold gamma radiation dose. The nuclear criticality safety (NCS) in NEDC-33621P divides the SFP into two regions. Region 1 continues to take credit for Boraflex. This requires accurate or bounding predictions of the amount and location of Boraflex degradation. Region 2 does not take credit for Boraflex, but instead requires certain storage locations to remain empty to maintain sub-criticality requirements.

For Region 1, which continues to take credit for Boraflex, NEDC-33621P calculated a 95/95 k_{eff} less than 0.95. This was based on a uniform Boraflex degradation from a nominal ^{10}B areal density of 0.0204 g/cm^2 to a minimum ^{10}B areal density of 0.0167 g/cm^2 and a complex algorithm to identify the combination of Boraflex gaps/cracks and local dissolution that resulted in a 95/95 k_{eff} combination. However, the NRC staff has not completed its review of the algorithms the licensee is using to predict and model Boraflex degradation in the NCS analysis.

Region 2 does not take credit for Boraflex, but instead requires certain storage locations to remain empty to maintain sub-criticality requirements. The Region 2 consists of a repeating pattern of a 4x4 array of storage cells in which six storage cells must be empty. NEDC-33621P calculated a 95/95 k_{eff} less than 0.95. However, NEDC-33621P did not include a misloading of a fuel assembly as an accident. The NRC considers misloading events to be credible events for fuel handling activities in the SFP. The licensee has not yet completed its analysis of a misloading event.

The final resolution of these items will not be resolved in time to meet the EPU schedule. Therefore, the licensee has proposed a license condition 2.C.(45), regarding the spent fuel pool, which is more limiting than that contained in NEDC-33621P. The license condition will only be applicable until the NCS analysis is approved or the end of the licensee's Cycle 19. This places a time limit on resolving the issue and as such is consistent with current NRC practice. The license condition would limit Region 1 cells to those which do not have any Boraflex panel with a ^{10}B areal density less than of 0.0179 g/cm^2 and/or a gamma dose greater than 2.3E10 rads. The ^{10}B areal density provides some margin to that listed in NEDC-33621P which when coupled with the dose threshold is acceptable. The Region 2 storage cells would be restricted to only allow storage of fuel assemblies with a standard cold core geometry (SCCG) k-infinity (k_∞) of 1.21. NEDC-33621P used a SCCG k_∞ of 1.26. Therefore, the SCCG k_∞ of 1.21 provides margin to accommodate a potential misloading event.

Conclusion

The NRC staff concludes that the licensee's proposed license condition provides reasonable assurance of compliance with GDC 62 until the detailed NCS analysis review can completed. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the spent fuel storage.

2.8.7 Topics from GEH LTR NEDC-33173P Supplement 3

Regulatory Evaluation

GGNS referenced NEDC-33173P (IMLTR) to justify application of GE-Hitachi (GEH) methods to GGNS EPU. By letter dated December 28, 2010 (Reference 165), the NRC staff issued the SE for NEDC-33173P Supplement 3, "Applicability of GE Methods to Expanded Operating Domains – Supplement for GNF2 Fuel." The NRC staff concludes that all NRC staff guidance, limitations, and conclusions documented in the SE for the Interim Methods Licensing Topical Report (IMLTR) remain applicable for GNF2 as originally stated.

Each condition specified in the NRC staff SE for NEDC-33173P and NEDC-33173P Supplement 3 was evaluated to verify the following for GGNS EPU:

- The analytical methods and codes used to perform the design-bases safety analyses will be applied within the applicable NRC-approved validation ranges. The calculation and measurement uncertainties applied to thermal limit calculations and the models simulating physical phenomena will remain valid for the predicted neutronic and thermal hydraulic core and fuel conditions during steady-state, transient, and accident conditions. The qualification database supporting analytical models simulating physical phenomena remains valid and applicable to the conditions under which it is applied, including those models and key parameters in which specific uncertainties are not applied.

- If the NRC-approved analytical methods and codes are extended outside the applicability ranges, the extension of the specific models are demonstrated to be acceptable or additional margins are applied to the affected downstream safety analyses until such time the supporting qualification data is extended.

Technical Evaluation

Condition 1: TGBLA/PANAC Version

IMLTR SE Condition

The neutronic methods used to simulate the reactor core response and that feed into the downstream safety analyses supporting operation at EPU/MELLLA+ will apply TGBLA06/PANAC11 or later NRC-approved version of the neutronic method.

PUSAR Disposition

TGBLA06/PANAC11 methods are used in the safety analysis. The NRC staff has approved the IMLTR Supplement 3 for GNF2 fuel design. Therefore, the NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 2: 3D MONICORE

IMLTR SE Condition

For EPU/MELLLA+ applications, relying on TGBLA04/PANAC10 methods, the bundle reactor monitoring system (RMS) difference uncertainty will be established from plant-specific core-tracking data, based on TGBLA04/PANAC10. The use of plant-specific trend line based on the neutronic method employed will capture the actual bundle power uncertainty of the core monitoring system.

PUSAR Disposition

Appendix A of the GGNS PUSAR states that the GGNS 3D MONICORE core monitoring system is based on TGBLA06/PANAC11 methods. Therefore, the NRC staff concludes that this condition is not applicable to GGNS.

Condition 3: Power to Flow Ratio

IMLTR SE Condition

Plant-specific EPU and expanded operating domain applications will confirm that the core thermal power to core flow ratio will not exceed 50 MWt/Mlbm/hr at any statepoint in the allowed operating domain. For plants that exceed the power-to-flow value of 50 MWt/Mlbm/hr, the application will provide power distribution assessment to establish that neutronic methods axial and nodal power distribution uncertainties have not increased.

PUSAR Disposition

Section 2.8.2.4.2 of the GGNS PUSAR states that the power to flow ratio at the low flow point at rated power (115 percent OLTP / 92.8 percent rated core flow) is less than 50 MWt/Mlbm/hr. The NRC staff confirmed that the power to flow ratio at the highest thermal power at the minimum flow point is less than 50 MWt/Mlbm/hr based on the plant information provided in the

PUSAR. The power/flow operating map does not change from cycle to cycle. The NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 4: SLMCPR 1

IMLTR SE Condition

For EPU operation, a 0.02 value shall be added to the cycle-specific SLMCPR value. This adder is applicable to SLO, which is derived from the dual loop SLMCPR value.

PUSAR Disposition

Section 2.8.2.2.1 of the PUSAR confirms that 0.02 adder will be applied to the cycle-specific SLMCPR as part of the reload licensing analysis (RLA). The NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 5: SLMCPR 2

IMLTR SE Condition

For operation at MELLLA+, including operation at the EPU power levels at the achievable core flow statepoint, a 0.03 value shall be added to the cycle-specific SLMCPR value.

PUSAR Disposition

The current LAR is for EPU operation. As the current LAR does not request approval to operate in the MELLLA+ domain this condition is not applicable to the current LAR.

Condition 6: R-factor

IMLTR SE Condition

The plant-specific R-factor calculation at a bundle level will be consistent with lattice axial void conditions expected for the hot channel operating state. The plant-specific EPU/MELLLA+ application will confirm that the R-factor calculation is consistent with the hot channel axial void conditions.

PUSAR Disposition

Section 2.8.2.4.3 of the PUSAR provides the basis for the R-factor calculation. The IMLTR condition requires that the R-factor be calculated using representative axial void conditions based on the core loading. Figure 2.8-18 of the PUSAR provides the distribution of bundle average void fractions for the low CPR (potentially limiting) bundles based on a reference GNF2 fueled core. The distribution of these bundle void fractions demonstrates that an average bundle void fraction of 60 percent is reasonable to characterize the potentially limiting bundles. Therefore, the NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 7: ECCS-LOCA 1

IMLTR SE Condition

For applications requesting implementation of EPU or expanded operating domains, including MELLLA+, the small and large break ECCS-LOCA analyses will include top-peaked and mid-peaked power shape in establishing the MAPLHGR and determining the PCT. This limitation is applicable to both the licensing bases PCT and the upper bound PCT. The plant-specific applications will report the limiting small and large break licensing basis and upper bound PCTs.

PUSAR Disposition

Condition 7 of the NRC SER for the IMLTR requires that the ECCS-LOCA performance analyses consider both top-peaked and mid-peaked power distributions. Section 2.8.5.6.2 of the PUSAR provides the results of the ECCS-LOCA analyses. Table 2.8-7 of the PUSAR provides the results of the limiting Appendix K small and large break LOCA analyses as well as the limiting nominal small and large break LOCA analyses. The table provides the results calculated for both mid-peaked and top-peaked power shapes. On this basis the NRC staff concludes that the analysis is consistent with the NRC staff's condition. As both results are provided the NRC staff concludes that Table 2.8-14 provides an adequate basis to determine the limiting axial power shape for ECCS-LOCA evaluations. Therefore, the NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 8: ECCS-LOCA 2

IMLTR SE Condition

The ECCS-LOCA will be performed for all statepoints in the upper boundary of the expanded operating domain, including the minimum core flow statepoints, the transition statepoint as defined in NEDC-33006P-A, Revision 3 (Reference 181), and the 55 percent core flow statepoint. The plant-specific application will report the limiting ECCS-LOCA results as well as the rated power and flow results. The SRLR will include both the limiting statepoint ECCS-LOCA results and the rated conditions ECCS-LOCA results.

PUSAR Disposition

Condition 8 of the NRC SER for the IMLTR is applicable to MELLLA+ operation. As the current LAR does not request approval to operate in the MELLLA+ domain this condition is not applicable to the current LAR.

Condition 9: Transient LHGR 1

IMLTR SE Condition

Plant-specific EPU and MELLLA+ applications will demonstrate and document that during normal operation and core-wide AOOs, the T-M acceptance criteria as specified in Amendment 22 to GESTAR II will be met. Specifically, during an AOO, the licensing application will demonstrate that the: (1) loss of fuel rod mechanical integrity will not occur due to fuel melting and (2) loss of fuel rod mechanical integrity will not occur due to pellet–cladding mechanical interaction. The plant-specific application will demonstrate that the T-M acceptance criteria are met for the both the UO2 and the limiting GdO2 rods.

PUSAR Disposition

Section 2.8.5.2.1 of the PUSAR documents the results of the AOO T-M analysis. The PUSAR analysis considered the potentially limiting AOO pressurization transients, including equipment OOS considerations. The results considered both UO2 and GdO2 fuel rods. The limiting results were provided for margin to the fuel centerline and cladding plastic strain criteria. Therefore, the NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 10: Transient LHGR 2

IMLTR SE Condition

Each EPU and MELLLA+ fuel reload will document the calculation results of the analyses demonstrating compliance to transient T-M acceptance criteria. The plant T-M response will be provided with the SRLR or COLR, or it will be reported directly to the NRC as an attachment to the SRLR or COLR.

PUSAR Disposition

Section 2.8.5.2.1 of the PUSAR states acceptable fuel rod thermal-mechanical response will be documented in the SRLR or COLR consistent with Condition 10. Therefore, the NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 11: Transient LHGR 3

IMLTR SE Condition

To account for the impact of the void history bias, plant-specific EPU and MELLLA+ applications using either TRACG or ODYN will demonstrate an equivalent to 10 percent margin to the fuel centerline melt and the 1 percent cladding circumferential plastic strain acceptance criteria due to pellet-cladding mechanical interaction for all of limiting AOO transient events, including equipment out-of-service. Limiting transients in this case, refers to transients where the void reactivity coefficient plays a significant role (such as pressurization events). If the void history bias is incorporated into the transient model within the code, then the additional 10 percent margin to the fuel centerline melt and the 1 percent cladding circumferential plastic strain are no longer required.

PUSAR Disposition

Section 2.8.5.2.1 of the PUSAR provides the minimum calculated margin to the fuel centerline melt and cladding plastic strain criteria of 52.4 percent and 51.5 percent, respectively. These analyses demonstrate greater margin than the 10 percent required by Condition 11. Therefore, the NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 12: LHGR and Exposure Qualification

IMLTR SE Condition

In GE letter MFN 06-481 dated December 5, 2006 (Reference 182), GE committed to submit plenum fission gas and fuel exposure gamma scans as part of the revision to the T-M licensing process. The conclusions of the plenum fission gas and fuel exposure gamma scans of GE 10x10 fuel designs as operated will be submitted for NRC staff review and approval. This revision will be accomplished through an amendment to GESTAR II or in a T-M licensing LTR. PRIME (a newly developed T-M code) has been submitted to the NRC staff for review. Once the PRIME LTR and its application are approved, future license applications for EPU and MELLLA+ referencing LTR NEDC-33173P must utilize the PRIME T-M methods.

PUSAR Disposition

As described in Section 2.8.1 of this SE, the NRC staff has reviewed the PRIME T-M methodology (NEDC-33256P, NEDC-33257P, and NEDC-33258P), and documented its approval in its SE dated January 22, 2010 (Reference 162). The GNF2 fuel system design evaluation for GGNS EPU application has been performed using the updated PRIME T-M methods. Footnote 3 to Appendix A of the PUSAR states that the GSTR-Mechanical (GSTRM) thermal-mechanical properties will be used in the downstream codes until the changes have been implemented and the NRC has performed an audit of that process and published its SE. This is consistent with the NRC staff approval of IMLTR Supplement 4 describing the plan to implement PRIME models and inputs into downstream safety analysis codes.

In its letter dated April 21, 2011 (Reference 14), the licensee provided information to show compliance with the "Interim Process Thermal Overpower Condition" specified in Appendix A to the NRC staff safety evaluation that approved the PRIME T-M methodology. The licensee stated that the RWE TOP evaluation passed the GSTRM screening criterion. The LFWH RWE TOP evaluation result, however, exceeded the GSTRM screening criterion, and therefore UO2 and Gadolinia results were analyzed individually using the PRIME T-M UO2 limit and showed that the result for a limiting cycle exposure and pressurization condition, met the exposure dependent PRIME UO2 TOP limit. Therefore, these results are compliant with the "Interim Process Thermal Overpower Condition" specified in the NRC staff safety evaluation for PRIME T-M methods, and hence with the IMLTR condition.

Condition 13: Application of 10 Weight Percent Gadolinia

IMLTR SE Condition

Before applying 10 weight percent Gd (gadolinia loaded as burnable absorber) to licensing applications, including EPU and expanded operating domain, the NRC staff needs to review and approve the T-M LTR demonstrating that the T-M acceptance criteria specified in GESTAR II and Amendment 22 to GESTAR II can be met for steady-state and transient conditions. Specifically, the T-M application must demonstrate that the T-M acceptance criteria can be met for TOP and MOP conditions that bounds the response of plants operating at EPU and expanded operating domains at the most limiting statepoints, considering the operating flexibilities (e.g., equipment out-of-service). Before the use of 10 weight percent Gd for modern fuel designs, NRC must review and approve TGBLA06 qualification submittal. Where a fuel design refers to a design with Gd-bearing rods adjacent to vanished or water rods, the submittal should include specific information regarding acceptance criteria for the qualification and address any downstream impacts in terms of the safety analysis. The 10 weight percent Gd qualifications submittal can supplement this report.

PUSAR Disposition

Section 2.8.2.4.5 of the PUSAR states that the GGNS EPU bundle design will utilize less than 10 w/o gadolinia in the fuel. Therefore, the NRC staff concludes that this condition is not applicable to the current LAR.

Condition 14: Part 21 Evaluation of GSTRM Fuel Temperature Calculation

IMLTR SE Condition

Any conclusions drawn from the NRC staff evaluation of the GE's Part 21 report will be applicable to the GESTR-M T-M assessment of this SE for future license application. GE submitted the T-M Part 21 evaluation, which is currently under NRC staff review. Upon completion of its review, NRC staff will inform GE of its conclusions.

PUSAR Disposition

Appendix F of the IMLTR SE imposes a critical pressure penalty of 350 psi to the GE14 GSTRM analysis in the determination of thermal-mechanical operating limits (TMOLs). In accordance with the General Electric Standard Application for Reactor Fuel (GESTAR II) process (Reference 154), GNF revised the GE14 GESTAR II Compliance Report in April 2009 (Reference 183), to incorporate an updated TMOL. In its letter dated April 21, 2011 (Reference 14), the licensee clarified that the GE14 LHGR is based on the revised TMOL provided in Appendix C of the GE14 GESTAR II Compliance Report. In addition, the licensee clarified that the TMOL for GNF2 is based on the PRIME model.

Based on the above, the NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 15: Void Reactivity 1

IMLTR SE Condition

The void reactivity coefficient bias and uncertainties in TRACG for EPU and MELLLA+ must be representative of the lattice designs of the fuel loaded in the core.

PUSAR Disposition

Appendix A of the PUSAR states that TRACG methods are not utilized for AOO or ATWS analyses. However, TRACG04 calculations are performed for thermal-hydraulic stability analysis for the GGNS EPU.

The NRC staff has previously reviewed the application of TRACG04 to perform stability calculations for the ESBWR (see letter dated January 28, 2008; Reference 184). In particular, the NRC staff has reviewed the improved void reactivity coefficient biases and uncertainties for application to TRACG04 for transient analysis (see letter dated January 8, 2009; Reference 185), and in the case of the ESBWR, specifically to analyze stability.

TRACG02 has previously been approved to perform stability analyses, particularly the calculation of the DIVOM slope. In its review of NEDE-32906P, Supplement 3, "Migration to TRACG04/PANAC11 from TRACG02/PANAC10," May 2006 (the Migration LTR) (Reference 186), the NRC staff determined that thermal-hydraulic models were largely consistent between the two versions (most differences were for models related to LOCA phenomena). The NRC staff has inspected the implementation of TRACG04 for stability analyses at various BWR plants and concluded that the evaluation provided in GE-NE-0000-0052-5590, "TRACG04 DIVOM 10 CFR 50.59 Evaluation Basis," April 2006, shows that the results are essentially the same for TRACG02 as TRACG04 (see letters dated July 6, 2009; Reference 187 and May 15, 2007; Reference 188). Therefore, the NRC staff agrees that the results of the DIVOM slope calculation performed using either version of TRACG are essentially the same.

On these bases, the NRC staff concludes that the use of the approved, improved void reactivity coefficient biases and uncertainties is appropriate for the GGNS TRACG04 DIVOM analyses. Therefore, the NRC staff concludes that the limited use of TRACG04 in the GGNS safety analysis is consistent with the IMLTR SE Condition 15.

Condition 16: Void Reactivity 2

IMLTR SE Condition

A supplement to TRACG /PANAC11 for AOO is under NRC staff review. TRACG internally models the response surface for the void coefficient biases and uncertainties for known dependencies due to the relative moderator density and exposure on nodal basis. Therefore, the void history bias determined through the methods review can be incorporated into the response surface "known" bias or through changes in lattice physics/core simulator methods for establishing the instantaneous cross-sections. Including the bias in the calculations negates the need for ensuring that plant-specific applications show sufficient margin. For application of TRACG to EPU and MELLLA+ applications, the TRACG methodology must incorporate the void history bias. The manner in which this void history bias is accounted for will be established by the NRC staff SE approving NEDE-32906P, Supplement 3, "Migration to TRACG04/PANAC11 from TRACG02/PANAC10," May 2006. This limitation applies until the new TRACG/PANAC methodology is approved by the NRC staff.

PUSAR Disposition

Appendix A of the PUSAR states that TRACG methods are not utilized for AOO or ATWS analyses; however, TRACG04 calculations are performed for thermal-hydraulic stability analysis for the GGNS EPU. As discussed in Section 2.8.7.15 of this SE, the GGNS stability analyses are performed using the void reactivity coefficient bias and uncertainties that account for the void history biases. This correction model is the same model that was reviewed by the NRC staff during its review of the Migration LTR (Reference 186). The NRC staff, therefore, concludes that the GGNS EPU LAR is consistent with Condition 16 of the IMLTR SE.

Condition 17: Steady State Five Percent Bypass Voiding

IMLTR SE Condition

The instrumentation specification design bases limit the presence of bypass voiding to 5 percent (LPRM levels). Limiting the bypass voiding to less than 5 percent for long-term steady operation ensures that instrumentation is operated within the specification. For EPU and MELLLA+ operation, the bypass voiding will be evaluated on a cycle-specific basis to confirm that the void fraction remains below 5 percent at all LPRM levels when operating at steady-state conditions within the MELLLA+ upper boundary. The highest calculated bypass voiding at any LPRM level will be provided with the plant-specific SRLR.

PUSAR Disposition

Section 2.8.2.4.1 of the PUSAR provides a demonstration analysis of the steady-state bypass void fraction at the LPRM Level D. The analysis is performed using a conservative bounding ISCOR calculation that limits cross flow and maximizes the radial peaking factor for a four bundle set. The results of the calculation indicate that, for the reference configuration, the bypass void fraction is below 5 percent. The PUSAR states that the cycle-specific analysis will be documented in the cycle-specific SRLR. On these bases, the NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 18: Stability Setpoints Adjustment

IMLTR SE Condition

The NRC staff concludes that the presence bypass voiding at the low-flow conditions where instabilities are likely can result in calibration errors of less than 5 percent for OPRM cells and less than 2 percent for APRM signals. These calibration errors must be accounted for while determining the setpoints for any detect and suppress long-term methodology. The calibration values for the different long-term solutions are specified in the associated sections of the SER for the IMLTR, discussing the stability methodology.

PUSAR Disposition

Section 2.8.3.1.2 of the PUSAR provides the disposition of IMLTR SE Condition 18. GGNS relies on the BWR Owners' Group long-term stability solution Option III. Option III is predicated on a "detect and suppress" strategy and utilizes an oscillation power range monitor (OPRM) trip. Section 2.8.3.1.2 of the PUSAR states the OPRM setpoint is calculated according to an assumed 5 percent calibration error. The NRC staff concludes that this is consistent with Condition 18.

The PUSAR states that the APRM setpoints are not adjusted. The NRC staff agrees with the GGNS determination as the APRM signals are not utilized in the Option III detect and suppress solution. The PUSAR further states that the OLMCPR adder of 0.01 required by IMLTR SE

Condition 19 is not applied in the OPRM setpoint calculation. The NRC staff concludes that this approach is consistent with the IMLTR SE Condition Implementation letter dated September 18, 2008 (Reference 189). Including the OLMCPR 0.01 adder would reduce the conservatism in the calculated OPRM setpoint. Therefore, the NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 19: Void Quality Correlation 1

IMLTR SE Condition

For applications involving PANCEA/ODYN/ISCOR/TASC for operation at EPU and MELLLA+, an additional 0.01 will be added to the OLMCPR, until such time that GE expands the experimental database supporting the Findlay-Dix void-quality correlation to demonstrate the accuracy and performance of the void-quality correlation based on experimental data representative of the current fuel designs and operating conditions during steady-state, transient, and accident conditions.

PUSAR Disposition

Section 2.8.2.2.2 of the PUSAR states that the 0.01 OLMCPR adder specified by Condition 19 is applicable to GGNS EPU and will applied to the EPU core design through the RLA process. Therefore, the NRC staff concludes that the licensee complies with the IMLTR condition.

Condition 20: Void Quality Correlation 2

IMLTR SE Condition

The NRC staff is currently reviewing Supplement 3 to NEDE-32906P, "Migration to TRACG04/PANAC11 from TRACG02/PANAC10," dated May 2006. The adequacy of the TRACG interfacial shear model qualification for application to EPU and MELLLA+ will be addressed under this review. Any conclusions specified in the NRC staff SE approving Supplement 3 to LTR NEDC-32906P will be applicable as approved.

PUSAR Disposition

GGNS EPU transient analyses use ODYN. Therefore, the NRC staff concludes that this condition is not applicable to the current LAR.

Condition 21: Mixed Core Method 1

IMLTR SE Condition

Plants implementing EPU or MELLLA+ with mixed fuel vendor cores will provide plant-specific justification for extension of GE's analytical methods or codes. The content of the plant-specific application will cover the topics addressed in this SE as well as subjects relevant to application of GE's methods to legacy fuel. Alternatively, GE may supplement or revise LTR NEDC-33173P (Reference 60) for mixed core application.

PUSAR Disposition

The GGNS EPU core will consist entirely of GNF fuel designs. Therefore, the NRC staff concludes that this condition is not applicable to the current LAR.

Condition 22: Mixed Core Method 2

IMLTR SE Condition

For any plant-specific applications of TGBLA06 with fuel type characteristics not covered in this review, GE needs to provide assessment data similar to that provided for the GE fuels. The Interim Methods review is applicable to all GE lattices up to GE14. Fuel lattice designs, other than GE lattices up to GE14, with the following characteristics are not covered by this review:

- Square internal water channels or water crosses
- Gd rods simultaneously adjacent to water and vanished rods
- 11x11 lattices
- MOX fuel

The acceptability of the modified epithermal slowing down models in TGBLA06 has not been demonstrated for application to these or other geometries for expanded operating domains.

Significant changes in the Gd rod optical thickness will require an evaluation of the TGBLA06 radial flux and Gd depletion modeling before being applied. Increases in the lattice Gd loading that result in nodal reactivity biases beyond those previously established will require review before the GE methods may be applied.

PUSAR Disposition

The GGNS EPU core will consist entirely of GNF fuel designs. Therefore, the NRC staff concludes that this condition is not applicable to the current LAR.

Condition 23: MELLLA+ Eigenvalue Tracking

IMLTR SE Condition

In the first plant-specific implementation of MELLLA+, the cycle-specific eigenvalue tracking data will be evaluated and submitted to NRC to establish the performance of nuclear methods under the operation in the new operating domain. The following data will be analyzed:

- Hot critical eigenvalue,
- Cold critical eigenvalue,
- Nodal power distribution (measured and calculated traversing in-core probe (TIP) comparison),
- Bundle power distribution (measured and calculated TIP comparison),
- Thermal margin,
- Core flow and pressure drop uncertainties, and

- The MCPR Importance Parameter (MIP) Criterion (e.g., determine if core and fuel design selected is expected to produce a plant response outside the prior experience base).

Provision of evaluation of the core-tracking data will provide the NRC staff with bases to establish if operation at the expanded operating domain indicates: (1) changes in the performance of nuclear methods outside the EPU experience base; (2) changes in the available thermal margins; (3) need for changes in the uncertainties and NRC-approved criterion used in the SLMCPR methodology; or (4) any anomaly that may require corrective actions.

PUSAR Disposition

The current LAR is for EPU operation. As the current LAR does not request approval to operate in the MELLLA+ domain this condition is not applicable to the current LAR.

Condition 24: Plant Specific Application

IMLTR SE Condition

The plant-specific applications will provide prediction of key parameters for cycle exposures for operation at EPU (and MELLLA+ for MELLLA+ applications). The plant-specific prediction of these key parameters will be plotted against the EPU Reference Plant experience base and MELLLA+ operating experience, if available. For evaluation of the margins available in the fuel design limits, plant-specific applications will also provide quarter core map (assuming core symmetry) showing bundle power, bundle operating LHGR, and MCPR for beginning of cycle (BOC), middle of cycle (MOC), and end of cycle (EOC). Since the minimum margins to specific limits may occur at exposures other than the traditional BOC, MOC, and EOC, the data will be provided at these exposures.

PUSAR Disposition

Section 2.8.2.4.4 of the PUSAR provides the information required by Condition 24 in the plant-specific LAR. These data include calculations of the key operating parameters for cycle exposure at EPU conditions. These parameters are compared to equivalent parameters for the plants in the extended database described in the IMLTR. The NRC staff reviewed Figures 2.8-1 through 2.8-18 provided in the PUSAR. The NRC staff concludes that the information provided was sufficient to meet the requirements of Condition 24.

The NRC staff confirmed that the expected operational conditions for EPU at GGNS are expected to be consistent with the operating conditions for the plants and cycles included in the extended database. Therefore, the NRC staff concludes that the licensee complies with the IMLTR condition.

<u>Conclusion</u>

The NRC staff has reviewed the information provided in the PUSAR and the responses to the NRC staff's requests for additional information. On the basis of the disposition of IMLTR SE conditions in Appendix A of the PUSAR and the RAI responses the NRC staff concludes that the GGNS safety analyses were performed consistent with the approval of the GEH analytical methods described in NEDC-33173P. Therefore, the NRC staff concludes that the analysis methods are acceptable.

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with EPUs to ensure the adequacy of the sources of radioactivity used by the licensee as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes. The ELTR1, Section 5.4 (Reference 58), requires that the radiological consequences be evaluated to show that the NRC regulations are met for uprated power conditions. 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 plant's UFSAR related to liquid waste management systems and gaseous waste management systems. The NRC's acceptance criteria for source terms are based on (1) 10 CFR Part 20, "Standards for protection against radiation," insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas; (2) Appendix I, 'Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion "As Low as is Reasonably Achievable' for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," to 10 CFR Part 50, insofar as it establishes numerical guides for design objectives and limiting conditions for operation to meet the "as low as is reasonably achievable" criterion; and (3) GDC 60, "Control of releases of radioactive materials to the environment," for the radioactive waste management systems being able to control the releases of radioactive liquid and gaseous effluents to the environment. Specific review criteria are contained in SRP Section 11.1, "Source Terms" (Reference 62).

Technical Evaluation

The core isotopic inventory is a function of the core power level. The reactor coolant isotopic activity concentration is a function of the core power level, leakage from the fuel, radioactive decay and removal by coolant purification systems. The analyses supporting the EPU amendment included a core isotopic source term calculated for the EPU conditions and were performed with consideration of GNF2 fuel, which is the type of fuel GGNS currently uses. The assumed inventory of fission products in the reactor core and available for release to the containment is based on the proposed maximum power level of 4496 MWt, which is 1.17 times the GGNS OLTP of 3833 MWt, including 2 percent instrumentation uncertainty.

The licensee discussed impact of the EPU on the radiation sources in the reactor coolant in Section 2.9.1 of the PUSAR which was included in Attachment 5A of the September 8, 2010, EPU submittal letter. Radiation sources in the reactor coolant include activation products, activated corrosion products, and fission products. Typically, licensee's use guidelines in NRC-approved topical report NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4 (CLTR), Section 8.4 for its evaluation of the reactor coolant and source terms. However, because GGNS uses GNF2 fuel and it is not enveloped by the bounding analysis performed for the CLTR, the CLTR is not applicable for fuel design dependent evaluations. Therefore, the methods and assumptions for the CLTR radiological evaluation are not applicable. For the EPU at GGNS, the radiological evaluation was performed using the methods and assumptions outlined in ELTR1, which is an NRC-approved document.

During reactor operation, some stable isotopes in the coolant passing through the core become radioactive (activated) as a result of nuclear reactions. For example, the non-radioactive isotope oxygen-16 (O-16) is activated to become radioactive nitrogen-16 (N–16) by a neutron-proton reaction as it passes through the neutron-rich core at power. Coolant activation, especially N–16 activity, is the dominant source of radiation in the turbine building and in the lower regions of the drywell. The increase in activation of the water in the core region is in approximate proportion to the increase in thermal power. In Table 2.9-1 of the PUSAR, the licensee's calculated reactor coolant activation concentrations due to EPU are shown to be significantly lower than the GGNS design-basis values. Resultant dose rates in the MSLs, turbines, and condenser area will increase roughly proportional to power uprate due to the fact that the transport time from core exit of the coolant to downstream points will decrease with increased flow. Therefore, no change is required in the activation design-basis reactor coolant concentrations for EPU and all CLTR dispositions are met for coolant activation products. The NRC staff concludes that the licensee's evaluation follows the guidelines in CLTR and SRP Section 11.1 and is, therefore, acceptable. The NRC staff considered GE proprietary information to make its determination.

The CLTR states that increases in reactor power will increase the activity of corrosion products and fission products found in reactor coolant. The reactor coolant contains activated corrosion products, which are the result of metallic materials entering the water and being activated in the reactor region. Under EPU conditions, the feedwater flow increases with power, the activation rate in the reactor region increases with power, and the filtration run-lengths of the condensate demineralizers may decrease as a result of the feedwater flow increase. The net result is an increase in the activated corrosion product present in the coolant.

Fission products in the reactor coolant are separable into the products in the steam and the products in the reactor water as a result of minimal normal operating releases from the fuel rods. The activity in the steam consists of noble gases released from the core plus carryover activity from the reactor water. This activity is the noble gas offgas that is included in the GGNS design. The licensee calculated offgas rates for EPU after 30 minutes decay to be 0.064 curies per second (Ci/sec), which is within the original design basis of 0.1 Ci/sec. Because the calculated offgas rates are lower than the design-basis offgas rates, the NRC staff concludes that no change is required in the GGNS design basis for offgas activity for the EPU. Therefore, the NRC staff concludes that the current GGNS design basis for offgas activity remains bounding for the EPU.

The fission product activity in the reactor water, like the activity in the steam, is the result of minute releases from the fuel rods. The EPU fission product activity levels in the reactor water remain to be a fraction (12 percent) of the design-basis fission product activity. The total activated corrosion product activity was calculated to be 1 percent greater than design-basis levels. However, the sum of the activated corrosion product activity and the fission product activity remain a fraction (14 percent) of the total design-basis activity in reactor water. Therefore, the NRC staff concludes that the activated corrosion product and fission product activities design bases for GGNS are unchanged for EPU. The NRC staff concludes that this is acceptable because the calculated fission product activity in the reactor coolant system (RCS) in the CLB remains bounding.

Based on the above evaluations, and considering that the licensee has used methodologies in the current GGNS licensing basis to evaluate the impact of the EPU on the radiation sources in the reactor coolant, the NRC staff concludes that the licensee's evaluation acceptable.

Conclusion

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

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

Regulatory Evaluation

The NRC staff reviewed the DBA radiological consequences analyses submitted by the licensee in support of the EPU. The radiological consequences analyses reviewed are the LOCA, fuel handling accident (FHA), control rod drop accident (CRDA), main steam line break accident (MSLBA), pressure controller failure accident, MSIV (MSIV) closure accident, misplaced bundle accident, offgas system leak or failure, radioactive liquid waste system leak or failure accident, liquid radwaste tank failure, and recirculation pump seizure. The NRC staff's review for each accident analysis included (1) the sequence of events and (2) models, assumptions, and values of parameter inputs used by the licensee for the calculation of the total effective dose equivalent (TEDE), or whole body and thyroid dose limits, where applicable. The NRC's acceptance criteria for radiological consequences analyses using an alternative source term are based on (1) 10 CFR 50.67, "Accident source term," insofar as it sets standards for radiological consequences of a postulated accident, and (2) GDC 19, "Control room," 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 rem TEDE, as defined in 10 CFR 50.2, "Definitions," for the duration of the accident. Specific review criteria are contained in SRP Section 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms" (Reference 62).

Technical Evaluation

In its previous review of the GGNS alternative source term (AST) amendment (Amendment 145, letter dated March 14, 2001; Reference 152), the NRC staff compared the doses estimated by the licensee to the applicable regulatory acceptance criteria and concludes, with reasonable assurance, that the licensee's estimates of the offsite and CR doses will comply with the applicable regulatory criteria in 10 CFR 50.67. In the SE for the AST amendment, the NRC staff concluded that the radiological consequences of DBAs will remain bounding up to a thermal power of 3910 MWt, or approximately 1.02 times the original licensed power limit of 3833 MWt. However, the EPU LAR proposes to increase the RTP to 4408 MWt, or approximately 1.15 times the current licensed thermal power (CLTP). Therefore, the licensee re-analyzed each DBA to determine the effect of the proposed increase in power over that which was previously analyzed. This calculated impact of the EPU on the radiological dose consequence of DBAs is discussed in Section 2.9.2 of the PUSAR (Reference 57) and in the licensee's responses to NRC staff RAIs dated April 14 and June 21, 2011 (References 13 and 14, respectively).

ELTR1 provides generic guidelines for justifying operation at up to 20 percent increased core thermal power. The guidelines for the performance of radiological evaluations are contained in Section 5.4 and Appendix H of ELTR1. Section 5.4 states that the magnitude of the potential radiological consequences of a DBA is proportional to the quantity of fission products released to the environment. This release depends on the activity released from the core and the transport mechanisms between the core and the effluent release point. In general, the inventory of fission products in the fuel rods, the creation of radioactive materials outside of the fuel by irradiation, and the concentration of radioactive material in the reactor coolant system are directly proportional to the RTP. Thus, an increase in the RTP can be expected to increase the inventory of radioactive material that is available for release. The previously analyzed transport mechanisms could be affected by plant modifications associated with the power uprate, potentially resulting in a larger release rate. ELTR1 states that the EPU application will provide justification that current radiological consequences are still bounding and within applicable criteria, or reanalysis of any areas adversely affected by the proposed uprate.

Section 2.7 of the NRC staff's position on ELTR1 stated that the existing calculations found in the plant's safety analysis report should remain valid as a result of the EPU and that the doses will be increased by the magnitude of the change in the source term. The NRC staff noted that the increased doses must meet the dose acceptance criteria in the plant's licensing basis and that the licensee must demonstrate assumptions and conditions stated in the ELTR1 are met. If these assumptions are not met, applicants will be expected to recalculate the affected radiological analyses.

The changes to the DBA analyses made by the licensee, and the evaluation by the NRC staff are discussed in further detail in the following sections.

2.9.2.1 Radiological Consequences of a Design-Basis Loss-of-Coolant-Accident

The GGNS LOCA was updated in support of the GGNS AST amendment which was reviewed and approved as Amendment 145 to the GGNS license. This event postulates a circumferential break in a recirculation loop pipe resulting in a loss-of-coolant to the core prior to initiation of the ECCS. For the EPU the licensee has evaluated the LOCA analysis at a thermal power of 4496 MWt. Fission product release fractions from the core are based on the guidance provided in RG 1.183 (Reference 140). The licensee calculated the radiological consequences for the following three potential fission product release pathways after the postulated LOCA:

(1) containment leakage;

(2) MSIV leakage; and

(3) post-LOCA leakage from Engineered Safety Features (ESF) systems outside containment

The licensee described containment leakage as fission products from the core being released to the drywell and then transported to the primary containment. Plate-out of elemental iodine and natural deposition of aerosols is credited in the drywell. The pH of the suppression pool is controlled to a value above 7.0. Therefore, re-evolution of the iodines from the pool is not considered. Airborne activity in the primary containment is removed by sprays and by plate-out. Airborne activity in the primary containment will leak into the secondary containment at a specified rate. Airborne activity in the secondary containment is released to the environment via the standby gas treatment system (SGTS). The secondary containment draw-down time is considered in the GGNS current design analysis.

In the EPU LAR, the licensee stated that the suppression pH response is impacted by a modification to the standby liquid control (SLC) system in conjunction with the EPU. This modification increases the boron-10 enrichment of the contents of the SLC tank while reducing the sodium pentaborate concentration. The licensee stated that the final SLC system design was determined to deliver sufficient sodium pentaborate to the containment/drywell pools to maintain a pH greater than 7.0 for 30 days post-LOCA taking into consideration increased acid production due to EPU radiation environments.

For the leakage from the MSIVs, there is a 250 standard cubic feet per hour (scfh) leak rate for the first 24 hours, and 125 scfh after 24 hours. It is conservatively assumed that during the first 20 minutes post-LOCA, the release goes directly to the environment. After 20 minutes, the release is assumed to go to the secondary containment. For ESF liquid leakage outside the primary containment, only halogens are assumed to be released. The ECCS leak rate is 1.12 gpm (10 minutes to 30 days). The iodine flash fraction is 10 percent. The above assumptions are consistent with GGNS current design basis. The NRC staff reviewed the proposed changes against the analysis performed for the AST and information in the GGNS UFSAR to confirm that no other analysis methods or inputs were changed from those used in Amendment 145 to the GGNS license.

To evaluate the impact of the EPU on the LOCA dose consequences, the licensee performed an isotope-by-isotope comparison between the current license source term and the EPU source term. The EPU source terms were based on thermal power level of 4496 MWt, which is

2 percent higher than the proposed power uprate level to account for instrument uncertainty. The releases of the iodines, noble gases, and alkali metals were calculated to increase in the range of 13-15 percent. The licensee conservatively used 15 percent to scale up the EPU dose results. The resulting doses for the LOCA analysis can be found in Table 1 of Section 2.13.2.2.4 of this SE. The NRC staff concludes that the licensee scaling method follows the guidance in ELTR1. The NRC staff also concludes that the dose results continue to meet the regulatory criteria of 10 CFR 50.67. Note that the Technical Support Center (TSC) is located within the CR boundary so that the TSC doses are identical to the CR doses.

The NRC staff concludes that the EPU does impact the fission product inventory. Accordingly, the radiological consequences postulated in prior analyses were multiplied by the plant-specific scaling factors as described above. For the LOCA, there were no plant modifications that would impact the transport of radioactive material to the environment so no further adjustments or re-analysis were necessary. Therefore, the analysis remains consistent with its CLB analysis.

The NRC staff has evaluated the licensee's revisions to the DBA analysis of radiological consequences of a LOCA, and determined that the licensee has appropriately accounted for the effects of the proposed EPU on this analysis. The NRC staff further determined that the plant site and the dose-mitigating engineered safety features (ESFs) remain acceptable with respect to the radiological consequences of a postulated LOCA, as the calculated offsite and onsite doses at the EAB, the LPZ outer boundary, the technical support center, and in the CR are within the applicable acceptance criteria.

LOCA Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of the LOCA and concludes that the licensee has adequately accounted for the effects of the proposed EPU on this analysis. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated LOCA since the calculated TEDE doses at the EAB and the LPZ outer boundary are well within the exposure guideline values of 10 CFR 50.67. The NRC staff also concludes that the calculated dose for the CR meets the dose requirements of GDC 19 for DBAs. The EPU radiological dose consequences of a LOCA are shown in Table 2.9-1 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to the radiological consequences of LOCA.

Table 2.9-1. Radiological Consequences for GGNS LOCA (rem TEDE)

Location	Original AST	CLTP	EPU	Allowable Limit
CR	3.65	3.69	4.24	5
EAB	8.78	8.70	10.01	25
LPZ	5.32	5.15	5.92	25
TSC	3.65	3.69	4.24	5

2.9.2.2 Radiological Consequences of a Fuel Handling Accident

The GGNS FHA was updated in support of the GGNS AST amendment which was reviewed and approved as Amendment 145 to the GGNS license. This accident postulates the drop of a fuel assembly onto the reactor core or stored fuel bundles. It is postulated that a fuel assembly is being handled by the fuel handling platform over the spent fuel pool or by the refueling platform over the containment racks or reactor core. The postulated event assumes that when the hoist is at its fully-retracted position, the assembly and the mast drop striking seated irradiated fuel assemblies. All fuel rods in the dropped assembly and a number of rods in the struck assemblies are assumed to fail (a total of 2.03 fuel bundle cladding failures), releasing radioactive gases to the pool water. Radioactive gases pass from the water to the air above the drop area. The FHA is assumed to occur at 24 hours after shutdown. A radial peaking factor of 2.2 is applied to all activities released from the cladding failures. Only halogens and noble gases are assumed to be released, since the alkali metals are completely retained in the pool water. These assumptions are consistent with GGNS current design basis and RG 1.183 (Reference 140).

For the EPU, the licensee has evaluated the EPU source terms based on a thermal power of 4496 MWt. The licensee evaluated the FHA EPU dose based on the contribution of each isotope to the calculated dose in the current calculation and the predicted contribution of each isotope for EPU. For the EPU, the licensee evaluated the EPU source terms based on a thermal power of 4496 MWt. The doses from each isotope are then summed for a total dose for each of the site boundaries and the weighted dose scaling factor is calculated based on the ratio between the current and EPU total doses. The weighted EPU dose scaling factor applicable to the EAB and CR are calculated to be 1.18 and 1.12, respectively. The CLTP EAB and CR doses are then increased by the weighted scaling factor to develop an estimate for the doses at the EPU power level. The LPZ dose value is not reported because it is bounded by the site boundary dose, which is consistent with GGNS CLB. Based on the discussion above, the NRC staff concludes that the licensee's method used to determine the scaling factors to be consistent with NRC-approved ELTR1.

In recalculating the fission product inventory, the licensee used the ELTR1 guidelines regarding the assessment for the impacts of the EPU and higher burnup fuel impact on radionuclide composition and inventory. ELTR1 states that existing calculation found in a nuclear plant's safety analysis report should remain valid as a result of power uprate with the doses being increased by the magnitude of the change in the source term. This is provided on the core design and the fuel performance characteristics not being changed significantly as a result of the power uprate, and the operating cycle of the core is not extended. Both of these criteria are met for the proposed amendment. For the FHA, the NRC staff reviewed the proposed changes against the analysis performed for the AST and information in the GGNS UFSAR to confirm that no other analysis methods or inputs were changed from those used in Amendment 145 to the GGNS license. Therefore, the transport of radioactive material to the environment is not changed, so no further adjustments or reanalysis were necessary.

The NRC staff has evaluated the licensee's revisions to the analysis of radiological consequences of a FHA, and determined that the licensee has appropriately accounted for the effects of the proposed EPU on this analysis. The NRC staff further determined that all credible plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated FHA, as the calculated offsite and onsite doses at the EAB, the LPZ outer boundary, and in the CR are within the applicable acceptance criteria.

FHA Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of FHA and concludes that the licensee has adequately accounted for the effects of the proposed EPU on this analysis. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated FHA since the calculated TEDE doses at the EAB and the LPZ outer boundary are well within (25 percent of) the exposure guideline values of 10 CFR 50.67. The NRC staff also concludes that the calculated dose for the CR meets the dose requirements of GDC 19 for DBAs. The EPU radiological dose consequences of an FHA are shown in Table 2.9-2 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to the radiological consequences of FHA.

Table 2.9-2. Radiological Consequences for GGNS FHA (rem TEDE)

Location	Original AST	CLTP	EPU	Allowable Limit
CR	2.04	2.80	3.14	5
EAB	1.98	2.64	3.12	6.3
LPZ	NA	NA	NA	NA

2.9.2.3 Radiological Consequences of a Control Rod Drop Accident

The GGNS CRDA was updated in support of the GGNS AST which was reviewed and approved as Amendment 145 to the GGNS license. This postulated accident scenario represents the dropping of a control rod out of the reactor core. The accident is analyzed with a radial peaking factor of 1.7. In essence, the CRDA is postulated as a rapid control rod withdrawal from the core, resulting in the failure of 16 fuel bundles (out of 800 bundles in the core) representing the four-bundle cell associated with the dropped control blade and one additional surrounding row. Of the failed fuel that is not assumed to melt, only gap activity, comprised of 10 percent of the noble gases, 10 percent of the halogens, and 12 percent of the alkali metals, is postulated to be released to the RCS. It is also assumed 0.77 percent of the failed fuel bundles experience fuel-melt. From that melted fuel, 100 percent of the noble gases, 50 percent of the halogens and 25 percent of the alkali metals are released to the RCS. The percentages of RCS activities transported to the turbine and condenser are assumed as follows: 100 percent of the noble gases, 10 percent of the halogens, and 1 percent of the remaining radionuclides.
The percentages of turbine/condenser activities available for release to the environment are assumed as follows: 100 percent of the noble gases, 10 percent of the halogens, and 1 percent of the remaining radionuclides. The leak rate from the condenser to the environment is assumed as 1 percent per day for 24 hours. These assumptions are consistent with RG 1.183 (Reference 140).

For the EPU, the licensee has evaluated the EPU source terms based on a thermal power of 4496 MWt. The licensee evaluated the CRDA EPU dose based on the contribution of each isotope to the calculated dose in the current calculation and the predicted contribution of each isotope for EPU. For the EPU, the licensee evaluated the EPU source terms based on a thermal power of 4496 MWt. The doses from each isotope are then summed for a total dose for each of the site boundaries and the weighted dose scaling factor is calculated based on the ratio between the current and EPU total doses. The weighted EPU dose scaling factor applicable to the EAB, LPZ, and CR are calculated to be 0.977, 1.02, and 1.11, respectively. The CLTP EAB, LPZ, and CR doses are then increased by the weighted scaling factor to develop an estimate for the doses at the EPU power level. Based on the discussion above, the NRC staff concludes that the licensee's method used to determine the scaling factors to be appropriate and consistent with NRC-approved ELTR1.

In recalculating the fission product inventory, the licensee used the ELTR1 guidelines regarding the assessment for the impacts of the EPU and higher burnup fuel impact on radionuclide composition and inventory. ELTR1 states that existing calculation found in a nuclear plant's safety analysis report should remain valid as a result of power uprate with the doses being increased by the magnitude of the change in the source term. This is provided on the core design and the fuel performance characteristics not being changed significantly as a result of the power uprate, and the operating cycle of the core is not extended. Both of these criteria are met for the proposed amendment. For the CRDA, the NRC staff reviewed the proposed changes against the analysis performed for the AST and information in the GGNS UFSAR to confirm that no other analysis methods or inputs were changed from those used in Amendment 145 to the GGNS license. Therefore, the transport of radioactive material to the environment is not changed, so no further adjustments or reanalysis were necessary.

The NRC staff has evaluated the licensee's revisions to the analysis of radiological consequences of a CRDA, and determined that the licensee has appropriately accounted for the effects of the proposed EPU on this analysis. The NRC staff further determined that all credible plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated CRDA, as the calculated offsite and onsite doses at the EAB, the LPZ outer boundary, and in the CR are within the applicable acceptance criteria.

CRDA Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of a CRDA and concludes that the licensee has adequately accounted for the effects of the proposed EPU on these analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated control rod drop accident since the calculated TEDE doses at the EAB and the LPZ outer boundary are well within (25 percent of) the exposure guideline values in 10 CFR 50.67 and meet the regulatory dose acceptance criteria of 6.3 rem TEDE in RG 1.183 and SRP 15.0.1. The NRC staff also concludes that the calculated dose for the CR meets the dose requirements of GDC 19 for DBAs. The EPU radiological dose consequences of a CRDA are shown in Table 2.9-3 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to the radiological consequences of a CRDA.

Table 2.9-3. Radiological Consequences for GGNS CRDA (rem TEDE)

Location	Original AST	CLTP	EPU	Allowable Limit
CR	0.262	0.262	0.291	5
EAB	0.147	0.151	0.151	6.3
LPZ	0.064	0.0723	0.0736	6.3

2.9.2.4 Radiological Consequences of a MSLB Outside Containment Accident

For the GGNS MSLBA, it is postulated that a guillotine break of one of the four MSLs occurs immediately downstream of the outermost MSIV outside the primary containment. A significant amount of reactor coolant is assumed to be released to the environment before the MSIVs isolate and the steam header depressurizes. Iodine and noble gas isotopes are released to the environment as a result of this accident. These isotopes are conservatively assumed to be the maximum iodine and noble gas inventories in the reactor coolant and steam allowed by GGNS TS .4.8, "Reactor Coolant System (RCS) Specific Activity," and TS 3.7.5, "Main Condenser Offgas," and are independent of power level. The TS iodine concentrations are based on the following:

- Equilibrium Iodine Case: 0.2 microcuries per gram (μCi/g) Dose Equivalent I-131
- Iodine Spiking Case: 4.0 μCi/g Dose Equivalent I-131

The TS noble gas release concentrations in steam are based on 380 millicuries per second (mCi/sec) release rate after 30 minutes decay. The reactor coolant is released from the break point to the environment in the form of steam (27,750 pound-mass (lbm)) and liquid (112,250 lbm). The assumptions and values discussed above are consistent with GGNS CLB.

The postulated release scenario for the current GGNS MSLBA is not affected by the EPU. The assumption of no fuel failure/melt in the MSLBA is consistent with the guidance in RG 1.183 (Reference 140) and is not affected by the EPU. Therefore, the MSLBA dose estimates will not be affected by EPU.

The NRC staff has evaluated the licensee's revisions to the analysis of radiological consequences of a MSLBA presented above, and concludes that the licensee has appropriately accounted for the effects of the proposed EPU on this analysis. The NRC determined that the resultant doses, both for the equilibrium iodine case and for the iodine spiking case, are within the NRC acceptance criteria. The NRC staff further concludes that all credible plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated MSLBA, as the calculated offsite and onsite doses at the EAB, the LPZ outer boundary, and in the CR are within the applicable acceptance criteria.

MSLBA Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of an MSLB outside containment and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated MSLB outside containment since the calculated TEDE doses at the EAB and the LPZ outer boundary do not exceed the exposure guideline values of 10 CFR 50.67 (assuming a pre-accident iodine spike) and are a small fraction of the 10 CFR 50.67 values for an MSLB with the primary coolant at the maximum equilibrium concentration for continued full-power operation. The NRC staff also concludes that the CR meets the dose requirements of GDC 19 for DBAs. The EPU radiological dose consequences of a MSLBA are shown in Table 2.9-4 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to a postulated failure of an MSLB outside containment.

Table 2.9-4. Radiological Consequences for GGNS MSLBA (rem TEDE)

Location	CLTP	EPU	Allowable Limit
Spike			
CR	0.153	0.153	5
EAB	0.123	0.123	25
LPZ	NA	NA	25
Equilibrium			
CR	3.01	3.01	5
EAB	2.39	2.39	2.5
LPZ	NA	NA	2.5

2.9.2.5 Radiological Consequences of a Pressure Controller Failure

The GGNS pressure controller failure postulates a pressure regulator failure with an assumed core wide fuel failure with the gap activity in the fuel being released to the RCS with isolation of the MSLs following reactor scram. The gap activity in the fuel is released with the steam into the suppression pool via the SRVs. Ten percent of the iodines and 1 percent of the alkali metals are assumed to reach the suppression pool. Suppression pool decontamination factors

(DFs) of 20 and 35 are applied to particulate and elemental iodines, respectively. All the released noble gases are assumed to reach the containment atmosphere. The activity that evolves into the containment from the suppression pool is released via the containment ventilation system in the high volume purge over a period of 10 seconds before the containment is automatically isolated. Two halogen compositions of iodine species are considered: (a) 97 percent elemental and 3 percent organic, and (b) 95 percent aerosol, 0.15 percent organic, and 4.85 percent elemental. Composition (a) yields larger doses and is therefore the limiting case. These assumptions are consistent with GGNS CLB and remain unchanged for the EPU.

For the EPU, the licensee has evaluated the EPU source terms based on a thermal power of 4496 MWt. The licensee evaluated the pressure controller failure EPU dose based on the contribution of each isotope to the calculated dose in the current calculation and the predicted increase in each isotope for EPU. For the EPU, the licensee evaluated the EPU source terms based on a thermal power of 4496 MWt. The doses from each isotope are then summed for a total dose for each of the site boundaries and the weighted dose scaling factor is calculated based on the ratio between the current and EPU total doses. The weighted EPU dose scaling factor applicable to the EAB, LPZ, and CR are calculated to be 1.07, 1.07, and 1.10, respectively. The CLTP EAB, LPZ, and CR doses are then increased by the weighted scaling factor to develop an estimate for the doses at the EPU power level. Based on the discussion above the NRC staff concludes that the licensee's method used to determine the scaling factors to be appropriate and consistent with NRC-approved ELTR1.

In recalculating the fission product inventory, the licensee used the ELTR1 guidelines regarding the assessment for the impacts of the EPU and higher burnup fuel impact on radionuclide composition and inventory. For the pressure controller failure, the NRC staff reviewed the proposed changes against the information in the GGNS UFSAR to confirm that no other analysis methods or inputs were changed from those used in Amendment 145 to the GGNS license. Therefore, the transport of radioactive material to the environment is not changed, so no further adjustments or reanalysis were necessary.

The NRC staff has evaluated the licensee's revisions to the analysis of radiological consequences of a pressure controller failure, and concludes that the licensee has appropriately accounted for the effects of the proposed EPU on this analysis. The NRC staff further concludes that all credible plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated pressure controller failure, as the calculated offsite and onsite doses at the EAB, the LPZ outer boundary, and in the CR are within the applicable acceptance criteria.

Pressure Controller Failure Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of a pressure controller failure and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated pressure controller failure since the calculated TEDE doses at the EAB and the LPZ outer boundary do not exceed the exposure guideline values of 10 CFR 50.67. The NRC staff also concludes that the CR meets the dose requirements of GDC 19 for DBAs. The EPU radiological dose consequences of a pressure controller failure are shown in Table 2.9-5 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to a postulated pressure controller failure.

Table 2.9-5. Radiological Consequences for GGNS Pressure Controller Failure (rem TEDE)

Location	CLTP	EPU	Allowable Limit
CR	3.39	3.74	5
EAB	2.28	2.43	2.5
LPZ	0.52	0.56	2.5

2.9.2.6 Radiological Consequences of a MSIV Closure

The GGNS MSIV closure event is an unplanned event in which a postulated MSIV closure may cause an immediate closure of all the other MSIVs depending on reactor conditions. This event is considered to be a moderate frequency event in which it is assumed no fuel failure occurs, but reactor coolant activities are released into the suppression pool via the SRVs. Radioactivity not scrubbed by the suppression pool water is assumed to be released into the containment atmosphere and then to the environment. The currently assumed steam mass in the reactor and steam lines remains applicable at 34,000 pounds.

In accordance with GGNS TS 3.4.8, the Calculation of Record (COR) postulates that the reactor coolant activity concentrations are at the maximum permitted iodine spiking concentrations with a dose equivalent I-131 specific activity of 4.0 μCi/gram. Only the EAB dose is evaluated consistent with the CLB. The limiting concentration is independent of power level. Therefore, the accident dose estimates will not be affected by EPU.

The release scenario is not affected by the EPU. The NRC staff reviewed the proposed changes against the information in the GGNS UFSAR to confirm that the assumption of no fuel failure/melt in the COR remains valid for EPU. The TS based reactor coolant activity concentrations are not impacted by the EPU. Consequently, the result of the COR analysis is not affected by EPU.

MSIV Closure Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of a MSIV closure and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated MSIV closure since the calculated TEDE doses at the EAB are within the regulatory dose acceptance criteria. The EPU radiological dose consequences of a MSIV closure are shown in Table 2.9-6 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to a postulated failure of an MSIV closure.

Table 2.9-6. Radiological Consequences for GGNS MSIVC (millirem TEDE)

Location	CLTP	EPU	Allowable Limit
EAB	0.083	0.083	100

2.9.2.7 Radiological Consequences of a Misplaced Bundle Accident

The GGNS misplaced bundle accident (also known as a fuel loading error event) postulates the improper loading of a fuel bundle and subsequent operation of the core. Five fuel bundles are assumed to fail (i.e., the misplaced bundle and the 4 surrounding bundles), releasing the associated gap activity into the RCS. For those plants without a main steam high radiation isolation trip, such as GGNS, 100 percent of the noble gases, 10 percent of the iodines, and 1 percent of the alkali metals are estimated to reach the condenser. Only noble gases are released to the environment via the offgas system. For the EPU, the licensee has evaluated the EPU source terms based on a thermal power of 4496 MWt with a radial peaking factor of 2.5, and an additional safety factor of 1.4, which is consistent with GGNS CLB. The gap activity, comprised of 10 percent of noble gases, 10 percent iodines, and 20 percent alkali metals, are not affected by the EPU.

For the postulated misplaced bundle accident, the release scenario is not affected by the EPU. The NRC staff reviewed the fuel failure assumptions in the COR and determined using engineering judgment that the assumptions remain valid for the EPU. The condenser inleakage is not affected because the Krypton (Kr) and Xenon (Xe) delay times are not affected by EPU. Therefore, EPU will not cause an increase in the current licensing-basis doses and, therefore, will not cause the EAB and CR doses to exceed regulatory limits. The LPZ dose is not recorded which is consistent with the CLB. For the misplaced bundle accident, the licensee asserts and the NRC staff reviewed the proposed changes against the information in the GGNS UFSAR to confirm that no other analysis methods or inputs were changed from those used in its CLB.

Conclusion Regarding Misplaced Bundle Accident

The NRC staff has evaluated the licensee's accident analyses for the radiological consequences of a misplaced bundle accident and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated misplaced bundle accident since the calculated

TEDE doses at the EAB and the CR do not exceed the exposure guideline values of 10 CFR 50.67 (assuming a pre-accident iodine spike) and are a small fraction (10 percent of) of the 10 CFR 50.67 values for a misplaced bundle accident with the primary coolant at the maximum equilibrium concentration for continued full-power operation. The NRC staff also concludes that the CR meets the dose requirements of GDC 19 for DBAs. The EPU radiological dose consequences of a misplaced bundle accident are shown in Table 2.9-7 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to a postulated failure of a misplaced bundle accident.

Table 2.9-7. Radiological Consequences for GGNS Misplaced Bundle Accident

Location	CLTP	EPU	Allowable Limit
CR	< 5.0	< 5.0	5.0
EAB	≈ 0.02	≈ 0.02	2.5

2.9.2.8 Radiological Consequences of an Offgas System Leak or Failure

The GGNS postulated offgas system leak or failure is the rupture of the offgas system pressure boundary. The failure is assumed to be a break in the charcoal delay line, resulting in releases from (1) charcoal adsorber failure, (2) delay line failure, and (3) continued operation of the steam jet air ejector (SJAE) for 1 hour. Consistent with GGNS CLB, the noble gas activity in the offgas system is based on a continuous release of 399,000 µCi/sec noble gas after 30 minutes decay (which includes a margin for measurement uncertainty). The particulate releases (noble gas daughters) from the failed charcoal adsorbers currently correspond to an analyzed core power level of 3910 MWt.

The offgas failure and release paths are not affected by EPU. The delay line transit time is not affected by power level. The charcoal bed hold-up time calculated in the COR is based on a NUREG-0016, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Boiling-Water Reactors (BWR-GALE Code)," Revision 1, dated January 1979 (Reference 190), methodology and is not adversely impacted by EPU.

According to NRC Regulatory Guide (RG) 1.98, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Radioactive Offgas System Failure in Boiling Water Reactor," March 1976 (Reference 191), the noble gas activity release rate is directly proportional to the core power level. For the GGNS EPU, a scaling factor of 1.15 was used which correlates with the 15 percent proposed power uprate. The NRC staff concludes that licensee's scaling method to be consistent with the guidance in RG 1.98.

<u>Offgas System Leak or Failure Conclusion</u>

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of an offgas system leak or failure and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated offgas system leak or failure since the calculated doses at the EAB and the LPZ outer boundary do not exceed the exposure guideline values of 10 CFR 100. The NRC staff also concludes that the CR meets the dose requirements of 10 CFR 50.67. The EPU radiological dose consequences of an offgas system leak or failure are shown in Table 2.9-8 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to a postulated failure of an offgas system leak or failure.

Table 2.9-8. Radiological Consequences for GGNS Offgas System Leak or Failure (rem)

Location	CLTP	EPU	Allowable Limit
EAB-Thyroid	Negligible	Negligible	75
LPZ-Thyroid	Negligible	Negligible	75
CR-TEDE	0.124	0.143	5
EAB-Whole Body	1.68	1.93	6
LPZ-Whole Body	0.384	0.442	6

2.9.2.9 Radiological Consequences of a Radioactive Liquid Waste System Leak or Failure

The GGNS radioactive liquid waste system leak or failure is postulated as the failure of the limiting radwaste system vessel, with a resulting release of iodine isotopes to the atmosphere. It has been determined that the limiting radwaste system vessel is the equipment drain collection tank. In the evaluation of the radiological consequences of this accident, the following assumptions are made:

- Radioisotope inventory in liquid radwaste system is based on normal system operation.
- Only radioiodine isotopes are released since noble gases are not present and particulate radioisotopes will not become airborne.
- The entire airborne iodine inventory is assumed to be in the elemental chemical species.
- No operator mitigation is assumed.
- Instantaneous release is assumed.
- No credit is taken for partition, filtration, holdup, or dilution of iodine once it is released from the failed tank.

For the EPU, the licensee has evaluated the EPU source terms based on a thermal power of 4496 MWt. Since only iodine isotopes are postulated to be released, the impact of the change in fuel cycle length is minimal. The scaling factor for this event is determined by dividing EPU rated power, including uncertainty, by OLTP power; this results in a scaling factor of 1.17, for the EAB, LPZ, and CR. The CLTP EAB, LPZ, and CR doses are then increased by the weighted scaling factor to develop an estimate for the doses at the EPU power level. The EPU doses were found to be below of the regulatory limits stated in 10 CFR Part 100, "Reactor Site Criteria," for the EAB and LPZ, and GDC 19 for the CR, which is in accordance with the GGNS CLB. The release scenario is not affected by the EPU. Since only iodine isotopes are postulated to be released, the impact of the change in fuel cycle length is minimal. The NRC staff concludes that the licensee's approach to be consistent with guidance in ELTR1.

Liquid Waste System Leak or Failure Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of a radioactive liquid waste system leak or failure and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated radioactive liquid waste system leak or failure since the calculated doses at the EAB and the LPZ outer boundary do not exceed the exposure guideline values of 10 CFR Part 100. The NRC staff also concludes that the CR meets the dose requirements of GDC 19 for DBAs. The EPU radiological dose consequences of a radioactive liquid waste system leak or failure are shown in Table 2.9-9 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to a postulated failure of a radioactive liquid waste system leak or failure.

Table 2.9-9. Radiological Consequences for GGNS Radioactive Liquid Waste System Leak or Failure (EAB rem)

Location	CLTP	EPU	Allowable Limit
CR-Thyroid	0.251	0.297	30
EAB-Thyroid	0.247	0.290	30
LPZ-Thyroid	0.0547	0.0642	30
CR-Whole Body	0.000163	0.000191	5
EAB-Whole Body	0.00474	0.00556	2.5
LPZ-Whole Body	0.00105	0.00123	2.5

2.9.2.10 Radiological Consequences of a Liquid Radwaste Tank Failure

The postulated GGNS liquid radwaste tank failure results in the largest release to groundwater of significant radionuclides in the liquid radwaste system. That tank has been determined to be the reactor water cleanup system (RWCU) phase separator decay tank in the radwaste building, and its failure is considered to be a limiting fault.

The fuel cycle length is assumed to be 24 months. The nuclides considered are strontium-90 (Sr-90) and cesium-137 (Cs-137) because they comprise the greatest potential health hazard in the event of an accidental spill. The concentrations of Sr-90 and Cs-137 are reduced to below maximum permissible concentration (MPC) at a distance of about 57 ft from the plant. The concentration of the contaminants at the Mississippi River after the estimated ground water travel time of 12.5 years to reach the river would be essentially zero (<10-20 μCi/cc). The EPU scale-up ratio is determined by taking the product of the power scale-up ratio and the fuel cycle scale-up ratio.

Applying the resultant scale-up ratio to the current radiological consequence dose value would yield an EPU result that would remain negligible. Based on engineering judgment, the NRC staff concludes that the licensee's approach to be adequate.

Liquid Radwaste Tank Failure Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of a liquid radwaste system tank and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated liquid radwaste system tank since the calculated doses at the EAB and the LPZ outer boundary do not exceed the exposure guideline values of 10 CFR Part 100. The NRC staff also concludes that the CR meets the dose requirements of GDC 19 for DBAs. The EPU radiological dose consequences of a liquid radwaste system tank failure are shown in Table 2.9-10 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to a postulated failure of a liquid radwaste system tank.

Table 2.9-10. Radiological Consequences for GGNS Liquid Radwaste Tank Failure (Release to Groundwater)

Radioactive Activity Concentration Reaching the River	
CLTP Concentration	< 10^{-20}µCi/cc (essentially zero)
EPU Concentration	< 10^{-20}µCi/cc (essentially zero)

2.9.2.11 Radiological Consequences of a Recirculation Pump Seizure Accident

The GGNS recirculation pump seizure accident is a postulated accident in which the operating recirculation pump suddenly stops rotating, causing a rapid decrease in core flow, heat transfer from fuel rods, and critical power ratio. For the EPU assessment of this event, the current CLTP dose consequences are scaled up by 15 percent, which correlates to the proposed thermal power increase. However, according to GGNS UFSAR Section 15.3.3.5, the consequences of a pump seizure during operation do not result in any fuel failure; radioactivity is nevertheless discharged to the suppression pool as a result of SRV actuation, similar to the MSIV closure event. However, the mass input, and hence activity input, for this event is much less than those consequences identified in the MSIV closure event. Therefore, the radiological dose consequences for the recirculation pump seizure accident are bounded by those for the MSIV closure event.

Recirculation Pump Seizure Accident Conclusion

The NRC staff has evaluated the licensee's revised accident analyses for the radiological consequences of a recirculation pump seizure accident and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the analyses. The NRC staff further concludes that the plant site and the dose-mitigating ESFs remain acceptable with respect to the radiological consequences of a postulated recirculation pump seizure accident since the calculated TEDE doses at the EAB and the LPZ outer boundary do not exceed the exposure guideline values of 10 CFR 50.67. The NRC staff also concludes that the CR meets the dose requirements of GDC 19 for DBAs. The EPU radiological dose consequences of a recirculation pump seizure accident are shown in Table 2.9-11 below. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to a postulated failure of a recirculation pump seizure accident.

Table 2.9-11. Radiological Consequences for GGNS Recirculation Pump Seizure

Location	CLTP	EPU	Allowable Limit
CR	3.72	4.28	5
EAB	1.886	2.17	2.5
LPZ	0.957	1.10	2.5

2.10 Health Physics

2.10.1 Occupational and Public Radiation Doses

The NRC staff conducted its review in this area to ascertain what overall effects operating GGNS at 4408 MWt (EPU) would have on both occupational and public radiation doses and to determine whether the licensee has taken the necessary steps to ensure that any dose increases will be maintained within applicable regulatory limits and as low as is reasonably achievable (ALARA).

The NRC staff's review included an evaluation of any increases in radiation sources and how this may affect plant area dose rates, plant radiation zones, and plant area accessibility. The NRC staff evaluated how personnel doses needed to access plant vital areas following an accident are affected. The NRC staff considered the effects of the proposed EPU on Nitrogen-16 (N-16) levels in the plant as well as any effects on radiation doses outside the plant, and at the site boundary, from skyshine. The NRC staff also considered the effects of the proposed EPU on plant effluent levels and any increased radiation doses from those effluents at the site boundary. The projected radiological impacts to the public from the site operating at EPU were evaluated as appropriate. The NRC's acceptance criteria for occupational and public radiation doses are based on 10 CFR Part 20, "Standards for protection against radiation," 40 CFR Part 190, "Environmental Radiation Protection Standards for Nuclear Power Operations," 10 CFR 50.67, "Accident Source Term," Appendix I, "Numerical Guides for Design Objectives and Limiting Conditions for Operation to Meet the Criterion 'As Low as is Reasonably Achievable' for Radioactive Material in Light-Water-Cooled Nuclear Power Reactor Effluents," to 10 CFR Part 50, and GDC 19, "Control room." Specific review criteria are contained in SRP Sections 12.2, "Radiation Sources," 12.3 - 12.4, "Radiation Protection Design Features," and 12.5, "Operational Radiation Protection Program"; item II.B.2 of NUREG-0737, "Clarification of TMI Action Plan Requirements," November 1980 (Reference 192); and other guidance provided in Matrix 10 of RS-001 (Reference 54).

Technical Evaluation

Source Terms

In general, the production of radiation and radioactive material (either fission or activation products) in the reactor core are directly dependent on the neutron flux and power level of the reactor. Therefore, as a first order approximation, a 15-20 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. However, due to the physical and chemical properties of the different radioactive materials that reside in the reactor coolant, and the various processes that transport these materials to locations in the plant outside the reactor, several radiation sources encountered in the BOP are not expected to change in direct proportion to the increased reactor power. The most significant of these are:

1. The concentration of noble gas and other volatile fission products in the MSL will not change. The increased production rate of these materials is offset by the corresponding increase in steam flow. Although the concentration of these materials in the steam line remains constant, the increased steam flow results in an increase in the rate at which these materials are introduced into the MC and offgas systems.

2. For the very short-lived activities, such as N-16 with its 7.13 second half-life, the decreased transit (and decay) time in the MSL, and the increased mass flow of the steam results in a larger increase in these activities in the major turbine building components. The N-16 dose rate is expected to increase by approximately 12 percent upstream of the MC, and up to 27 percent in the MC. However, the areas with a significant N-16 inventory are heavily shielded and not routinely occupied, and the N-16 is only present during operation. The licensee estimates a 27 percent increase in expected dose rates from the increase in N-16 in the turbine building over the OLTP dose rates.

3. The concentrations of non-volatile fission products, actinides, and corrosion and wear products in the reactor coolant are expected to increase proportionally with the power increase (approximately 13 percent). However, the increase in steam flow is expected to result in small increases in moisture carryover in the steam, resulting in some increased transport of these activities to the balance of the plant. The NRC staff assessed that the increases in moisture carryover are expected to be within the current design margin for moisture carryover. Associated increases in dose rates are also expected to be within the shielding design margins for the condensate, feedwater, and other affected systems.

Radiation Protection Design Features

Occupational and onsite radiation exposures.

The radiation sources in the core are expected to increase in proportion to the increase in power. This increase, however, is bounded by the existing safety margins of the plant design. Due to the design of the shielding and containment surrounding the reactor vessel, and since the reactor vessel is not accessible to plant personnel during operation, a 13 percent increase in the radiation sources in the reactor core will have minimal affect on occupational worker personnel doses during power operations. Similarly, the radiation shielding provided in the balance of plant is conservatively sized such that the increased source terms discussed above are not expected to significantly increase the dose rates in the normally occupied areas of the plant.

Radiation dose rates, in areas of the plant impacted by steam, are estimated to increase by approximately 27 percent. These areas are all currently designated as high radiation areas and personnel access to them is restricted and controlled accordingly. The existing radiation zoning design (e.g. the maximum designed dose rates for each area of the plant), for areas outside the steam-affected areas, will not change as a result of the increased dose rates associated with this EPU.

During EPU testing of each unit, the licensee will perform sampling and measurements to determine the radiochemical quality of the reactor water, feedwater, and gaseous releases. In addition general area dose rates will be measured at plant locations susceptible to increased N-16 and neutron doses as a result of the power increase. Surveys will be performed in normally accessible areas adjacent to steam-affected areas in the Reactor Building, Turbine Building, Guard Tower Building, and the Screenwell Building. These measurements and sampling will be performed at 100, 105, and 110 percent of CLTP and at 100 percent EPU.

Operating at a 15 percent higher power level will result in an increased core inventory of radioactive material that is available for release during postulated accident conditions. The plant shielding design must be sufficient to provide control room habitability, per GDC 19, and operator access to vital areas of the plant, per NUREG-0737, item II.B.2, during an accident. The EPU core power level is 4408 MWt and the safety analyses were performed at a reactor power level of 4496 MWt (with a 2 percent margin of power uncertainty) and a 24-month fuel cycle. Vital access area doses were previously calculated using a highly conservative source term. Specifically, the source terms were generated using a subset of the entire list of isotopes present in the core inventory. The activity adjustment factor of 1.266 was applied to all of the isotopes in the subset to account for the total T=0 hr core activity, in the event of a LOCA. Using the 1.266 factor was conservative when considering the decay of the short half life isotopes (those with half lives less than 30 minutes) because a time dependent adjustment factor would approach 1.0 for time periods greater than 30 minutes (T=30 minutes). Considering the current license basis source term of 4025 MWt multiplied by the 1.266 factor at all times post-LOCA, the post-accident mission does were effectively based on a core power level of 5095 MWt, thus, the anticipated mission doses did not change since such a large margin was used in previous calculations.

Therefore, following implementation of this EPU, GGNS 1 will continue to meet its design basis in terms of radiation shielding, in accordance with the criteria in SRP Section 12.4, "Radiation Protection Design Features" (Reference 62), GDC 19, and NUREG-0737, item II.B.2.

Public and offsite radiation exposures.

There are two factors associated with this EPU that may impact public and offsite radiation exposures during plant operations, which are (1) the possible increase in gaseous and liquid effluents released from the site, and (2) the increase in direct radiation exposure from radioactive plant components and solid wastes stored onsite. As described above, this EPU will result in a 13 percent increase in gaseous effluents released from the plant during operations and 19 percent increase in airborne doses in the particulate and iodine category, where the thyroid is the dominant organ relative to dose. This increase is a minor contribution to the radiation exposure of the public. The nominal annual public dose from plant gaseous effluents for GGNS is typically a small fraction of the design criteria of 10 CFR 50, Appendix I, and the EPA's dose limits in 40 CFR 190 (as referenced by 10 CFR 20.1301(e)). For example during the reporting period of January 1 to December 31, 2009, the maximum dose to a member of the public resulting from airborne releases from the GGNS plant, was much less than 1 percent of the dose criteria in Appendix I to 10 CFR Part 50, and 40 CFR Part 190. Even with the conservative assumption that GGNS power operations increases this by 50 percent, the dose to the public from airborne effluents will continue to be well below these applicable regulatory requirements.

This EPU will also result in increased generation of liquid and solid radioactive waste. The increased condensate feed flow associated with this EPU results in faster loading of the condensate demineralizers. Similarly, the higher feed flow introduces more impurities into the reactor resulting in faster loading of the RWCU system demineralizers. Therefore, the demineralizers in both of these systems will require more frequent backwashing to maintain them. The licensee has estimated that these more frequent backwashes will increase the volume of liquid waste that will need processing by less than 0.1 percent and an increase in processed solid radioactive waste by 0.004 m^3 per day. These increases are well within the processing capacity of the radwaste systems and are not expected to noticeably increase the liquid effluents or solid radioactive waste released from the plant. Therefore, these increases will have a negligible impact on occupational or public radiation exposure.

Skyshine is a physical phenomenon associated with gamma radiation that is emitted skyward, during radioactive decay. As this radiation interacts with air molecules, some is scattered back down to the ground where it can expose members of the public. Since there is significantly less radiation shielding above the steam components in the turbine building than there is to the sides of these components, skyshine from N-16 gammas can be a significant contributor to dose rates outside plant buildings (both onsite and offsite). As discussed above, the licensee has estimated that plant operations at EPU will increase the N-16 activity in the turbine building. In addition, the practice of injecting hydrogen into the reactor feedwater, to reduce stress-corrosion cracking, significantly increases the fraction of N-16 in the reactor water that is released into the steam during power operations. For the effluent reporting periods 2004 through 2009, the maximum annual offsite whole body dose was 2.76 millirem (mrem). Applying a conservative factor of 1.3 to account for the reduced decay time from increased GGNS steam flow rate, results in a maximum expected annual dose to an offsite member of the public of approximately 3.59 mrem. This is well within the annual limit of 25 mrem to an actual member of the public, as referenced by 10 CFR 20.1301(e).

Operational Radiation Protection Programs

The increased production of non-volatile fission products, actinides and corrosion and wear products in the reactor coolant may result in proportionally higher plate-out of these materials on the surfaces of, and low flow areas in, reactor systems. The corresponding increase in dose rates associated with these deposited materials will be an additional source of occupational exposure during the repair and maintenance of these systems. However, the current ALARA program practices at GGNS (e.g., work planning, source term minimization, etc.), coupled with existing radiation exposure procedural controls, will be able to compensate for the anticipated increases in dose rates associated with this EPU. Therefore, the increased radiation sources resulting from this proposed EPU, as discussed above, will not adversely impact the licensees ability to maintain occupational and public radiation doses resulting from plant operation to within the applicable limits in 10 CFR 20 and as low as is reasonably achievable (ALARA).

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on radiation source terms and plant radiation levels. The NRC staff concludes that the licensee has taken the necessary steps to ensure that any increases in radiation doses will be maintained ALARA. The NRC staff further concludes that the proposed EPU meets the requirements of 10 CFR Part 20, 40 CFR Part 190, Appendix I to 10 CFR Part 50, and NUREG-0737, item II.B.2. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable with respect to radiation protection and ensuring that occupational and public radiation exposures will be maintained within these applicable limits of ALARA.

2.11 Human Performance

2.11.1 Human Factors

Regulatory Evaluation

The NRC staff reviewed the EPU LAR to confirm that changes made to implement the proposed EPU will not adversely affect operator performance. The NRC 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 GDC 19, "Control room," 10 CFR 50.120, "Training and qualification of nuclear power plant personnel," 10 CFR Part 55, "Operator's Licenses," and the guidance in NRC Generic Letter (GL) 82-33, "Supplement 1 to NUREG-0737 – Requirements for Emergency Response Capability)," dated December 17, 1982 (Reference 193).. Specific review criteria are contained in SRP Sections 13.2.1, "Reactor Operator Requalification Program; Reactor Operator Training," 13.2.2, "Non-Licensed Plant Staffing Training," 13.5.2.1, "Operating and Emergency Operating Procedures," and 18.0, "Human Factors Engineering" (Reference 62), and RS-001 (Reference 54).

The GDCs in Appendix A to 10 CFR Part 50, effective May 21, 1971, and subsequently amended July 7, 1971, is applicable to GGNS. The human factors program is not described in any GGNS licensing basis document; however, it is governed by the GGNS Quality Assurance Program in accordance with controlled Engineering Standard ES-17, "Factors Design Criteria."

Technical Evaluation

The NRC staff has developed a standard set of questions, specifically, for the review of an EPU LAR regarding the human factors area. These questions were provided to the licensee by letter dated February 23, 2011 (Reference 7). The licensee responded to these questions by letter dated March 9, 2011 (Reference 9). The following are the NRC evaluations of the responses to the staff's questions.

2.11.1.1 Changes in Emergency and Abnormal Operating Procedures

By letter dated February 23, 2011, the NRC staff requested Entergy to describe how the proposed EPU will change the plant emergency and abnormal operating procedures (AOPs) (SRP Section 13.5.2.1, "Operating and Emergency Operating Procedures" (Reference 62)).

Licensee Response

The licensee performed a review of the effects of the proposed EPU on: (1) the ability to meet the above regulatory requirements; (2) margins available when setpoints are proposed to be changed, in particular, the setpoint for the SLCS pump discharge relief valve; and (3) operator actions specified in the EOPs (consistent with the generic emergency procedure guidelines/severe accident guidelines, EPGs/SAGs).

The licensee stated that the changes due to EPU do not require modification of operator instructions. When required by changes in plant configuration (as identified by the design change process), changes to EOPs, including changes to EOP calculations and plant data, are developed and implemented in accordance with plant administrative procedure for EOP program maintenance. GGNS performs EOP calculations consistent with the BWROG EPGs/SAGs Appendix C. BWROG, "Emergency Procedure and Severe Accident Guidelines (EPGs/SAGs), Revision 2," March 2001, is currently implemented at GGNS.

The EOP calculation input and output data will be reviewed and verified by Engineering. Changes to the EOP calculation outputs are forwarded to Operations for use in revising the EOP Procedures/Flow Charts and the SAGs and supporting documents. Critical software will be verified and validated by Engineering to generate expected EOP results.

There are no changes to the assumed operator actions for the EPU ATWS analysis. EPU implementation does not change operator strategy on ATWS level reduction or early boron injection. EPU will affect some of the calculated curves, but does not affect stability mitigation actions.

Finally, the EOP flow charts will be reviewed and validated by Operations, including trial use in the simulator. GGNS procedures, including system operating, abnormal, and emergency operating procedures, will be revised prior to implementing EPU.

The licensee has committed to have these changes in effect prior to implementing EPU (see the licensee's EPU LAR, Attachment 14, List of Commitments, commitment # 18).

NRC Staff Evaluation

Based on the licensee's review of operator actions included in EOPs and Off-Normal/AOPs, the configuration control processes used at GGNS to assure systematic consistency, and the verification and validation (V&V) processes used to assure the correctness and usability of EOP calculations, software, and affected procedures, the NRC staff concludes that the GGNS EOP/AOP change process is acceptable for implementing the proposed EPU. Additionally, the NRC staff concludes that Entergy's commitment #18, "GGNS procedures, including system operating, abnormal, and emergency operating procedures, will be revised prior to implementing EPU," is acceptable.

2.11.1.2 Changes to Operator Actions Sensitive to Power Uprate

By letter dated February 23, 2011, the NRC staff requested Entergy to:

a. Describe any new operator actions needed as a result of the proposed EPU.

b. Describe changes to any current operator actions related to emergency or abnormal operating procedures that will occur as a result of the proposed EPU. (SRP Section 18.0, "Human Factors Engineering" (Reference 62))

c. Identify and describe operator actions that will involve additional response time or will have reduced time available.

d. Address any operator workarounds that might affect these response times.

e. Identify any operator actions that are being automated or being changed from automatic to manual as a result of the power uprate. Provide justification for the acceptability of these changes).

Licensee Response

a. No new actions are required for EPU at GGNS, Unit 1.

b. The following EOP parameters have been identified as being affected:

- Heat Capacity Temperature Limit (HCTL) - The EPU will result in additional heat being added to the Suppression Pool (SP) during certain accident scenarios. The HCTL curve will be revised as a result of the increase in decay heat rejected to the SP. The change is not significant (approximately 1 °F).

- Pressure Suppression Pressure (PSP) - The PSP Curve will be revised as a result of the increase in reactor power and in decay heat loading. The change is not significant (<1 psi).

- Minimum Debris Retention Injection Rate – The Minimum Debris Retention Injection Rate will be revised as a result of the increase in decay heat loading. The injection flow will increase by approximately 10 percent of the CLTP flow.

- Cold Shutdown Boron Weight - The Cold Shutdown Boron Weight will increase in the equilibrium core design for EPU by approximately 18 percent. The Hot Shutdown Boron Weight is expected to be affected by an equivalent amount. The EOP/SAP revisions related to this parameter also consider the SLC system boron enrichment modification which mitigates this EPU effect.

The planned changes to abnormal operating procedures (AOPs), called Off-normal Event Procedures or ONEPs at GGNS, are listed below. The first group will be revised to rescale action points associated with reactor power:

- 05-1-02-I-2, Turbine and Generator Trips:
- 05-1-02-III-3, Reduction in Recirculation System Flowrate
- 05-1-02-III-5, Automatic Isolations;
- 05-1-02-V-5, Loss of Feedwater (feedwater) Heating;
- 05-1-02-V-7, Feedwater System Malfunctions;
- 05-1-02-V-8, Loss of Condenser Vacuum; and
- 05-1-02-V-11, Loss of Plant Service Water.

The second group below includes ONEPs requiring other supporting change(s) as described:

- 05-1-02-I-2, Turbine and Generator Trips – Revise generator hydrogen pressure regulator setting to reflect new EPU value.
- 05-I-02-I-4, Loss of AC Power – Change seal oil system nomenclature due to installation of a new seal oil system. Revise generator MVAR limits to reflect EPU values.
- 05-1-02-II-1, Shutdown from the Remote Shutdown Panel – Change operator response time to reflect EPU values
- 05-1-02-III-1, Inadequate Decay Heat Removal – Revise the decay heat curves, heat up rates and temperature related data sheets to reflect the new EPU values.
- 05-I-02-V-1, Loss of Component Cooling Water – Add subsequent operator actions to account for installation of CCW heat exchanger tube cleaning system.

- 05-I-02-V-2, Loss of Turbine Building Cooling Water – Incorporate changes required as a result of the installation of a new seal oil system.

- 05-1-02-V-5, Loss of Feedwater Heating – Revise the feedwater temperature vs. core power curve, which determines the actions to be taken in response to the event, to reflect the new EPU values.

- 05-1-02-V-7, Feedwater System Malfunctions – Change the Reactor Feed Pump Turbine (RFPT) critical speed parameter following replacement of RFPT. Update to reflect EPU condensate transient analysis.

- 05-1-02-V-11, Loss of Plant Service Water - Add subsequent operator actions to account for installation of CCW heat exchanger tube cleaning system.

- 5-1-002-V-12, Condensate / Reactor Water High Conductivity – Revise to reflect impact of CFFF and Leading Edge Flow Meter (LEFM) modifications.

The licensee's overall conclusion is that no changes to current operator actions and no new operator actions are required to support EPU. There are a few procedural actions being changed or added as a result of modifications to the plant concurrent with EPU, such as the installation of the Component Cooling Water heat exchanger tube cleaning system, and the installation of a new seal oil system. However, these are not required for EPU, and do not affect emergency or abnormal operation under EPU conditions.

c. Regarding operator actions that will involve additional response time or will have reduced time available, the following scenarios were considered:

    - The ATWS analysis assumes operator action in 120 seconds to initiate the SLCS and 660 seconds to initiate RHR SPC. These times *do not change* for EPU.

    - Long-term DBA LOCA assumes operators initiate containment cooling 30 minutes from initiation of the event. (UFSAR Section 6.2.2.3) In addition, manual isolation of the unfiltered outside air intake is credited at 20 minutes. (UFSAR Section 15.6.5.5.2). These times *do not change* for EPU.

    - For an SBO event, actions to establish reactor water level control and reactor pressure control are initiated 2 minutes into the event. This time does not change for EPU. The other 15-, 60- and 120-minute action times to defeat RCIC trips, reduce control room heat loads and reduce DC battery loads *remain unchanged* for EPU as well.

    - For Control Room Evacuation, there is *no change required* to the operator action time and *no new operator actions* are required.

- The Main Steam Line Break (MSLB) outside containment analysis assumes the operator begins depressurizing the Reactor Pressure Vessel (RPV) at the 10 minute mark. This time *does not change* for EPU.

- The Condensate Storage Tank (CST) was designed with a minimum volume to allow at least 8 hours of Reactor Core Isolation Cooling (RCIC) system operation at a constant reactor pressure to remove reactor decay heat. At EPU conditions, slightly less CST volume is available resulting in RCIC operation for 7.9 hours. This minor reduction in operating time does not affect operator actions. The EPU analysis shows there are *no significant changes* to the operator action times for EOPs.

The ONEPs are event-based procedures. UFSAR action times for events such as loss of AC power (station blackout) and shutdown from the remote shutdown panel (Appendix R fire) have been evaluated and *do not change* for EPU. In other cases, the procedures are designed so that the severity of the event dictates the time available for the response, ranging from immediate operator actions to more long range response. As with the EOPs discussed above, there are *no significant changes* to the operator action times for ONEPs.

d. Regarding operator workarounds, the licensee stated that:

GGNS is currently tracking two (2) operator workarounds:

(1) Radial well pumps cannot be controlled from a remote location and have to be started locally; and

(2) The Division 1 Load Shed Sequencer (LSS) switch requires declaring the Division 1 Diesel Generator INOPERABLE when it is paralleled to the grid.

Neither workaround currently impacts time-critical operator actions. Both are scheduled to be resolved prior to the startup from [RFO 18]. In addition, EPU implementation does not introduce any new operator workarounds.

e. Regarding any changes to the current level of automation, the licensee stated that no current operator actions will be automated, nor will any automated action be made manual.

<u>NRC Staff Evaluation</u>

a. The NRC staff concludes that since no new actions are required for EPU, further consideration is not needed – this is acceptable.

b. Based on the licensee's statements that there are no new credited operator actions required as a result of EPU, and that the analysis for EPU credits existing manual actions using the same time limits credited for CLTP (currently licensed thermal power), the NRC staff concludes that the licensee's position that there are no new or changed operator actions needed for EPU is acceptable.

c. Although available time for some operator actions has been reduced (those involving reduction of decay heat), the assumed operator response times in the licensee's analyses have not been changed and will be confirmed to be adequate during the training and V&V phases of the EPU. Based on this, the NRC staff concludes that the time available to complete operator actions to be acceptable, contingent on successful completion of timed simulator scenarios or equivalent with a representative sample of operators.

d. Based on the licensee's identification of two current operator workarounds that were assessed to have no effect on time-critical operator actions, and Entergy's intent to have no existing or new operator workarounds prior to startup under EPU conditions, the NRC staff concludes that this portion of the EPU LAR to be acceptable.

e. Based on the licensee's intent not to change the level of automation for any safety function, the NRC staff concludes that this portion of the EPU LAR acceptable.

2.11.1.3 Changes to Control Room Controls, Displays and Alarms

By letter dated February 23, 2011, the NRC staff requested Entergy to describe any changes the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms. For example, what zone markings (e.g. normal, marginal and out-of-tolerance ranges) on meters will change? What setpoints will change? How will the operators know of the change? Describe any controls, displays, alarms that will be upgraded from analog to digital instruments as a result of the proposed EPU and how operators will be tested to determine they could use the instruments reliably. (SRP Section 18.0, "Human Factors Engineering" (Reference 62))

<u>Licensee Response</u>

The licensee stated the following regarding control room changes:

> The effect on the control room instruments and controls is minimal. There are no changes to these systems/controls that will affect the operator's ability to interpret, read or respond to the information provided by the updated systems/controls. Plant process computer system operation is not affected by EPU.
>
> Changes to the control room are developed in accordance with the plant design change process. Under this process, a Human Factors engineering review is performed for changes associated with the GGNS control room. The change process also requires an "effect review" by Operations and Training personnel. Results of these reviews, including simulator effect and training requirements,

are incorporated into the engineering change package and tracked to completion by the design change process.

The licensee identified that following instrument and control systems are affected:

- For Main Steam Line (MSL) High Flow Group 1 Isolation, the analytical trip value remains the same in terms of percent power. The trip value for MSL High Flow Group 1 Isolation in terms of differential pressure is being revised to reflect the changes associated with the EPU RTP level increase and steam flow increase.

- The trip value for the Turbine First Stage Pressure Scram Bypass Permissive is being revised to reflect the changes associated with the High Pressure (HP) turbine modification and the EPU rated thermal power level increase. The absolute thermal power associated with the Turbine First Stage Pressure Scram Bypass Permissive remains unchanged. The specific first stage pressure associated with this power is being changed.

- Trip values for Average Power Range Monitors (APRMs) are being revised to reflect the changes associated with the EPU rated thermal power level increase.

- The Rod Worth Minimizer (RWM) and the Rod Block Monitor (RBM) setpoints remain at the same value in terms of percent. The absolute power values are being changed accordingly.

The following Balance of Plant (BOP) instrument setpoints/controls are affected:

- The overspeed setpoint on the reactor feedpump turbines is being increased to accommodate the increased speed demand at normal EPU operations.

- The condensate booster pump low suction pressure trip setpoint is being increased due to the increased condensate booster pump flow rates at EPU conditions.

- The pressure control system pressure regulator setting is being lowered to provide for the increased steam line pressure drop at EPU steam flow rates.

- The following control room instruments are affected by EPU:

    - Reactor feedwater flow and steam flow control room indicating meters and recorders are being modified to increase the usable range.

    - Main Turbine 1st Stage Steam Flow recorder indication is being rescaled.

- The Load Set and Load Meters on the electrohydralic control (EHC) panel are being replaced.

- Reactor Feed Pump Turbine speed meters are being rescaled.

- The Generator Amperage, MegaVARS, and Megawatt indication is being replaced.

During the EPU outage, a new system, the Power Range Neutron Monitoring System (PRNMS) was installed. The PRNMS equipment is designed to replace existing Average Power Range Monitor (APRM) components. The PRNMS has been evaluated separately by the NRC. Information regarding the PRNMS and its associated Human Factors Evaluation is provided in Entergy letter GNRO-2010/00075 to the NRC dated December 13, 2010 (Reference 194).

NRC Staff Evaluation

Based on the licensee's description of the control room changes required to support the EPU, the NRC staff concludes that the changes to be minor in terms of changes to the interface with operators. Primarily, the appearance and function of current instruments will not change, only the underlying setpoints will change. In addition, the few physical changes that are required are minor (e.g. rescaling) and are limited to BOP instrumentation. The NRC staff concludes that these changes to be acceptable. As stated above, the NRC review of PRNMS has been addressed separately, so no conclusion regarding the acceptability of PRNMS is provided herein.

2.11.1.4 Changes on the Safety Parameter Display System

By letter dated February 23, 2011, the NRC staff requested Entergy to describe any changes to the safety parameter display system resulting from the proposed EPU. How will the operators know of the changes? (SRP Section 18.0, "Human Factors Engineering" (Reference 62))

Licensee Response

The licensee stated that the information presented on the safety parameter display system (SPDS) displays and the method of presentation will remain unchanged for EPU; therefore, SPDS equipment is not being modified for the EPU. The SPDS system also provides procedure based display concepts to support execution of the GGNS EOPs. In conjunction with the changes required to the EOPs for EPU operation, two EOP curves, PSP and HCTL, are being revised. The EOP changes and supporting SPDS display modifications will be included in the Operator Training Program.

NRC Staff Evaluation

Based on the minor changes proposed to update affected display pages on the SPDS, the NRC staff concludes that the licensee's implementation of EPU is acceptable regarding the GGNS SPDS.

2.11.1.5 Changes to the Operator Training Program and the Control Room Simulator

By letter dated February 23, 2011, the NRC staff requested Entergy to describe any changes to the operator training program and the plant referenced control room simulator resulting from the proposed EPU, and provide the implementation schedule for making the changes. (SRP Sections 13.2.1, "Reactor Operator Requalification Program; Reactor Operator Training," and 13.2.2, "Non-Licensed Plant Staff Training" (Reference 62))

Licensee Response

The licensee stated that the Operations Training Group develops training for modifications that affect plant operation. Operator training may be presented in the classroom, on the simulator, in-plant, or a combination of venues as appropriate. The EPU training will focus on the plant modifications, procedure changes, start-up and test requirements, and other aspects of EPU being proposed for GGNS. The proposed training will highlight the changes that affect EOPs and ONEPs. Operator training will start in the 4th quarter 2011 and continue through startup from the EPU installation outage. Details of the training will be developed through the plant modification process, procedure change process, and the training development process. Detailed schedules will be developed in accordance with GGNS training procedures.

The licensee has made the following commitment regarding training and simulator updates:

> Commitment #19. As determined by the training analysis process, appropriate classroom, simulator and in-plant training will be conducted prior to power escalation or as required to operate modified systems for plant start up. The simulator will be modified to maintain the required fidelity in accordance with site procedures and ANSI/ANS 3.5 – 1998. The simulator changes include hardware changes for new and modified instrumentation and controls, software updates for modeling EPU changes and retuning of the core physics model for cycle specific data. Simulator performance will be validated using design analysis data and startup and test data from the EPU project and implementation program.

NRC Staff Evaluation

Based on the licensee's use of controlled processes to identify training needs and simulator updates, and its commitment to complete the proposed training prior to operation under EPU conditions, the NRC staff concludes that the licensee's proposed approach to training and simulator updates acceptable.

Conclusion

The NRC staff has reviewed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that the licensee has (1) appropriately accounted for the effects of the proposed EPU on operator actions and (2) taken appropriate actions to ensure that operator performance is not adversely affected by the proposed EPU. The NRC staff further concludes that the licensee has acceptably responded to the NRC staff's questions in RS-001 and its RAI. Therefore, the NRC staff concludes that the licensee's proposed EPU is acceptable regarding the human performance aspects of the identified system changes.

2.12 Power Ascension and Testing Plan

2.12.1 Approach to EPU Power Level and Test Plan

Regulatory Evaluation

The purpose of the EPU test program is to demonstrate that SSCs will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The NRC staff's review included an evaluation of: (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance; (2) 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 technical bases for this request follow the guidelines contained in the following NRC-approved General Electric Nuclear Energy (GENE) Licensing Topical Reports (LTRs) for EPU safety analysis: Licensing topical report NEDC-33004P-A, Constant Pressure Power Uprate, Revision 4, dated July 2003 (known as CLTR), provides an NRC-accepted approach for performing constant pressure power uprates (CPPU). The CPPU approach has been used as the basis of multiple power uprate license amendment requests submitted previously to the NRC. The CPPU approach maintains the plant's current maximum operating reactor pressure, and along with other required limitations and restrictions discussed in the CLTR, allows a simplified approach to power uprate analyses and evaluations.

Safety issues identified in NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (known as ELTR1), that should be addressed in a plant-specific EPU license amendment request, are addressed in the Power Uprate Safety Analysis Report (PUSAR). The NRC determined the ELTR1 to be an acceptable methodology for requesting EPUs. For issues that have been evaluated generically, the PUSAR references the NRC-approved generic evaluations in either ELTR1 or NEDC-32523P-A (known as ELTR2). Additionally, RS-001 (Reference 54) provides guidance to the NRC staff when performing reviews of EPU applications. The review standard was developed to enhance the consistency, quality, and completeness of the NRC staff's reviews and to inform licensees of the guidance documents the NRC staff would use when reviewing EPU applications. These documents provide the acceptance criteria for the areas of review allowing licensees to prepare EPU applications that are complete with respect to the areas that are within the NRC staff's scope of review. Section 3.2 of RS-001, Section 2.12, "Power Ascension and Testing Plan," provides the NRC staff an outline to follow when generating plant-specific safety evaluations. For example, PUSAR Section 2.12, Power Ascension and Testing Plan, provides a regulatory and technical evaluation to demonstrate that the EPU test program provides the assurance that the plant will continue to operate in accordance with the design criteria, and that SSCs will perform satisfactorily in service at the proposed EPU power level. Differences between the plant-specific design basis and RS-001 Regulatory Evaluations are described and evaluations provided. In summary, the PUSAR Technical Evaluations are based on NRC-approved topical reports CLTR, ELTR1, and ELTR2 and their associated Safety Evaluation Reports.

The NRC's acceptance criteria for the proposed EPU test program are based on Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," 10 CFR Part 50, Criterion XI, "Test Control," which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service. Additionally, specific review criteria are contained in Section III of SRP Section 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs" (Reference 62). The NRC staff's review focused on Entergy adequately addressing the guidance described in Section 2 and Insert 12 of RS-001. Entergy's proposed power ascension and test plan (PATP) follows the guidelines contained in NRC-approved GENE LTRs which the NRC staff determined to be an acceptable methodology for licensees requesting EPUs. The NRC staff's review focused on Entergy satisfying the requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," and addressing the guidance and review criteria in SRP 14.2.1.

Technical Evaluation

2.12.1.1 SRP 14.2.1, Section III.A, Comparison of Proposed EPU Test Program to the Initial Plant Test Program

SRP 14.2.1, Section III.A, specifies the guidance and acceptance criteria which the licensee should use to compare the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison should include: 1) all initial power-ascension tests performed at a power level of equal to or greater than 80 percent 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 applicable sections of the GGNS Updated Final Safety Analysis Report (UFSAR), specifically Chapter 14, "Initial Test Program," and Section 14.2, "Construction, Preoperational, and Initial Startup Test Program," which provided general requirements and an overview of the initial startup tests performed. The NRC staff also reviewed information in other applicable sections of the UFSAR which discussed general requirements, startup, and power ascension testing performed from initial plant startup to full rated power of 3833 MWt (OLTP) to demonstrate that the plant was capable of operating safely and satisfactorily. The NRC staff also reviewed the following information provided to the NRC staff in the EPU LAR dated September 8, 2010:

- Attachment 5A to Entergy letter GNRO-2010/00056, "Safety Analysis Report for Grand Gulf Nuclear Station Constant Pressure Power Uprate" (non-proprietary), NEDC-33477, Revision 0, August 2010, contained the power uprate safety analysis report (PUSAR) formatted in accordance with RS-001. The PUSAR is an integrated summary of the results of the safety analysis and evaluations performed specifically for the GGNS EPU and follows the guidelines contained in GENE CLTR NEDC-33004P-A, "Constant Pressure Power Uprate." The NRC staff has approved the use of this LTR for reference as a basis for an EPU license amendment request with the exception of the CLTR's proposed elimination of large transient testing (LTT).

- Attachment 8 to Entergy letter GNRO-2010/00056, "List of Planned Modifications," provided a list of modifications planned for EPU implementation which, as stated by Entergy, do not constitute regulatory commitments. The planned modifications will be implemented in accordance with the requirements of 10 CFR 50.59, "Changes, tests, and experiments," and are expected to be performed during refueling outage 18 (RFO 18).

- Attachment 9 to Entergy letter GNRO-2010/00056, "Extended Power Uprate Startup Test Plan," provided a discussion of the EPU testing planned and provided a comparison of the initial startup and EPU testing. Section 3.0 provided a discussion of Entergy's justification for not performing LTT. This enclosure supplements PUSAR Section 2.12.

The NRC staff concludes that all transient tests described in the initial startup test program were listed in Table 9-1 of Attachment 9 and, with one exception, were initially performed at 80 percent or greater of OLTP. LTT SU-25B (Full Reactor Isolation), originally performed at 75 percent OLTP, was extrapolated by Entergy to greater than 80 percent based on NRC letter dated May 13, 1985 (Reference 195), which approved use of inadvertent full MSIV isolation at 75 percent power to satisfy the 95-100 percent startup test. The purpose of the test is to determine the reactor transient behavior that results from the simultaneous full closure of all MSIVs.

Entergy's PATP for the GGNS does not include performing LTTs at full EPU power as part of the EPU LAR. The justification for not performing such tests was presented by Entergy in Sections 3.6, 3.7, and 3.10 of Attachment 9 of the EPU LAR, and Section 4.0 provides an overview of the PATP covering power ascension up to the full 115 percent OLTP (4408 MWt) condition to verify acceptable performance. Each EPU related test is described along with the applicable test conditions, governing procedures, and associated test acceptance criteria. Routine power ascension tests performed in accordance with existing engineering and surveillance procedures are provided in Table 9-1. The modifications, including component or system level testing required to implement the EPU, are listed in Table 9-2. Attachment 9 also provided a discussion of the planned EPU testing as compared to the initial startup tests. Entergy's justification for a test program that does not include all of the power-ascension testing that would normally be performed is further discussed in SRP 14.2.1, Section III.C, of this SE.

The PATP is an initial power ascension test plan designed to assess steam dryer and selected piping system performance from CLTP of 3898 MWt to full EPU conditions of 4408 MWt. Testing will be performed in accordance with the TSs and applicable procedures on instrumentation re-calibrated to EPU conditions. Steady-state data will be taken during power ascension and continuing at each EPU power increase increment. EPU power increases above 100 percent CLTP will be made along an established flow control/rod line in increments of equal to or less than 5 percent power. Steady-state data will be taken at points from 90 percent up to 100 percent of CLTP so that system performance parameters can be projected for EPU power before the CLTP is exceeded. Power ascension will occur over a period of time with gradual increases in power and hold periods. Entergy is also performing post-modification testing, calibration and normal surveillance, as required, to ensure that systems will operate in accordance with their design requirements.

In addition, the licensee has proposed a license condition that provides for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant structures, systems, and components (including verifying the continued structural integrity of the steam dryer) for power ascension from the previous LTP (3898 MWt) to the EPU level of 4408 MWt (or 115 percent of OLTP). The license condition requires Entergy to provide a PATP for the steam dryer testing.

This PATP shall include:

- Criteria for comparison and evaluation of projected strain and acceleration with on-dryer instrument data.
- Acceptance limits developed for each on-dryer strain gage and accelerometer.
- Tables of predicted dryer stresses at CLTP, strain amplitudes and PSDs at strain gage locations, acceleration amplitudes and PSDs at accelerometer locations, and maximum stresses and locations.

The PATP will provide correlations between measured accelerations and strains and the corresponding maximum stresses. The license condition requires that the PATP be submitted to the NRC Project Manager no later than 10 days before start-up.

This license condition is discussed in detail in Section 2.2.6.6 of this SE.

Conclusion

The NRC staff concludes through comparison of the documents referenced above, including a review of the initial startup tests and planned EPU testing described in Table 9-1 of Attachment 9 and applicable sections of Chapter 14, "Initial Test Program," of the GGNS UFSAR, 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 SRP 14.2.1 and other staff guidance provided in RS-001. Therefore, the NRC staff concludes that the proposed PATP is acceptable.

2.12.1.2 SRP 14.2.1, Section III.B, Post Modification Testing Requirements for Functions Important to Safety Impacted by EPU-Related Plant Modifications

Section III.B of SRP 14.2.1 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 NRC staff reviewed Attachment 8, "List of Planned Modifications," to the EPU LAR which described the planned modifications necessary to support the EPU, which will be implemented for RFO 18, currently scheduled for 2012, and Table 9-2 of Attachment 9 which provided additional information including anticipated post-modification testing involving component or system level testing. Entergy stated that the majority of the modifications involve secondary plant upgrades necessary to allow GGNS to achieve maximum EPU power, and that none of the modifications involve a first-of-a-kind modification to a system important to safety; introduce new system inter-dependencies or interactions; or change system response to initiating events. Entergy performed an aggregate impact analysis of the modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to anticipated initiating events to ensure that the testing program demonstrates adequate implementation of the EPU-related modifications necessary to support CPPU. The EPU testing program is in accordance with the startup test specifications described in PUSAR Section 2.12.1 and is based upon analyses and GE BWR experience with uprated plants to establish a standard set of tests for initial power ascension for CPPU. Post modification testing associated with the proposed modifications includes functional performance checks, component performance measurements, equipment calibrations and pressure drop measurements at full flow conditions. Some of the planned modifications considered by Entergy for EPU include high pressure main turbine replacement, steam dryer replacement, circulating water pump upgrades, main generator current transformer replacement, low pressure feedwater heater replacement, and various instrumentation setpoint adjustments. From a BOP perspective, unlike previous BWR EPUs, the proposed modifications to the power conversion system are minimal in scope and unlikely to cause the NRC staff the need to require an integrated transient test of the power conversion system.

Conclusion

The NRC staff concludes that the PATP proposed by GGNS demonstrates that EPU related modifications will be adequately implemented. Specifically, the NRC staff concludes that based on a review of the listing of completed and planned modifications, including post-maintenance testing associated with these modifications, the proposed EPU test program should adequately demonstrate the performance of SSCs. The NRC staff also concludes that the proposed PATP adequately identified plant modifications necessary to support operation at the uprated power level and complies with the criteria established in Section III.B of SRP Section 14.2.1.

2.12.1.3 SRP 14.2.1, Section III.C, Use of Evaluation to Justify Elimination of Power-Ascension Tests

Section III.C of SRP Section 14.2.1 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. Each secondary review branch will verify and document the adequacy of the licensee's justification for test exceptions that are within the branch's technical area of review. 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 NRC 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 NRC staff recognizes that licensees may propose a test program that does not include all of the power-ascension testing referred to in Sections III.A and III.B of SRP 14.2.1 that would normally be performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in SRP Section III.C.2. If a licensee proposed 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 PATP is relied upon as a quality check to: (a) confirm that analyses and any modifications and adjustments that are necessary for proposed EPUs have been properly implemented, and (b) 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 calculational 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 NRC 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.

In this section of the SE, the NRC staff reviewed Entergy's justification for not performing certain original startup tests against the review criteria established in SRP 14.2.1. The GGNS PATP does not include all the power ascension large transient testing that would typically be performed during initial startup of a new plant. Specifically, Entergy's PATP does not include performance of MSIV Functional Tests (SU-25A), Full Reactor Isolation Test (SU-25B), and Turbine Trip and Generator Load Rejection Test (SU-27), all of which are LTTs. Entergy provided a detailed discussion of the basis for elimination of these LTTs pursuant to certain sections discussed in the NRC staff's review criteria established in Section III.C.2 of SRP 14.2.1; and Section 3.0 and Table 9-1 of Attachment 9 to the EPU LAR. The following LTTs were performed during initial startup as discussed in Section 14.2.12.3 of the GGNS UFSAR and follow the tests described in Attachment 2 of SRP 14.2.1.

- <u>MSIV Functional Tests (SU-25A)</u>

  This initial startup test was performed to functionally check the MSIVs for proper operation at selected power levels, determine valve closure times, and to determine maximum power at which full closures of a single valve can be performed without a reactor scram. The test was initially performed at 84.2 percent OLTP and met all acceptance criteria.

- Closure of All MSIVs (SU-25B)

  This initial startup test required a simultaneous full closure of all MSIVs at 95 to 100 percent of RTP. The test objectives were to functionally check the MSIVs for proper operation at selected power levels, determine isolation valves' closure times, and to determine reactor transient behavior during and following simultaneous closure of all MSIVs. As discussed in Section 3.7 of Attachment 9, an inadvertent reactor full isolation occurred at 75 percent power and 100 percent core flow that fulfilled all of the objectives of the planned isolation from full power. Entergy stated that a May 13, 1985 letter from the NRC approved the deletion of the requirement to run the full reactor isolation startup test at 100 percent power based on the results of the 75 percent power isolation data analysis. Entergy cited industry operating experience at several similar BWR plants in its justification for not performing this test in its EPU PATP.

- Turbine Trip and Generator Load Rejection (SU-27)

  This initial startup test was performed to demonstrate the proper response of the reactor and its control systems to protective trips in the turbine and the generator. During the test, the turbine stop valves are tripped at selected reactor power levels and simultaneous opening of the main generator output breakers. The test was initiated from 100 percent reactor thermal power and 98 percent core flow. An evaluation performed by General Electric concluded that the results were acceptable based on an insignificant impact on the Chapter 15 UFSAR transient analysis. Entergy stated that all acceptance criteria were satisfied. Entergy cited both plant-specific GGNS and industry operating experience at several similar designed BWR plants in its justification for not performing this test in its EPU PATP. Entergy also cited GE ELTR1 criteria which recommend not performing this test based on the percentage increase requested in the EPU LAR.

Industry Operating Experience Relative to Large Transient Events

With respect to the review criteria established in SRP Section III.C.2, Entergy cited industry operating experience events at pre-EPU power levels that occurred at several BWR-5/6 units that are similar in design to GGNS (BWR 6 with Mark 3 containment). The NRC staff review of licensee event reports (LERs) associated with these events identified that all systems functioned as expected. Industry operating experience is a factor used by the NRC staff in its review of SRP Section III.C.2 with respect to the licensee not performing certain LTTs (e.g., Full Reactor Isolation test (SU-25B), and Turbine Trip and Generator Load Rejection test (SU-27).

Clinton Power Station, Unit 1

On December 18, 2000, a full MSIV closure occurred at the Clinton Power Station which is the same general reactor design as GGNS (BWR 6) from 100 percent power due to inadequate indication of an existing fault during performance of a surveillance test. The NRC staff review of Licensee Event Report (LER) 2000-007 identified that after opening of the MSIVs, reactor pressure control and water level was established; and no safety system functional failures occurred during the event. Also, on July 4, 2002, the sudden pressure alarm for the "B" Main Power Transformer actuated in the Main Control Room along with a simultaneous reactor scram from 95 percent reactor power, resulting in a generator and turbine trip and a reactor scram.

The licensee stated that no other automatic or manually initiated safety system responses were necessary to place the plant in a safe condition; and the Primary Containment isolation valves responded as expected.

River Bend Station

On December 4, 1994, an inadvertent full MSIV closure occurred at the River Bend Station (BWR 6) from 100 percent power during performance of a surveillance test. The NRC staff review of LER 94-030 identified that following an evaluation by the licensee, operator actions during the scram were appropriate and safety systems functioned as designed, including the automatic actuation of four SRVs.

Nine Mile Point Nuclear Station, Unit 2

Two events at the Nine Mile Point Nuclear Station (BWR 5) on October 15, 2001, and November 11, 2002, involved a reactor scram while operating at 104 percent OLTP (100 percent CLTP) as a result of closure of all MSIVs. The NRC staff review of LERs 2001-004 and 2002-004 identified that the licensee's review of the plant transient response to Section 15.2.4 of the USAR for both events confirmed that they were bounded by the USAR analysis; and that post-scram, feedwater, RCIC and HPCS functioned as designed to maintain reactor water level. On April 28, 1995, the NRC approved a 4.3 percent stretch power uprate (Reference 196).

BWR Industry Operating Experience at EPU Power Levels

Examples of post-EPU BWR industry operating experience not cited by the licensee in the EPU LAR included the following: On November 4, 2003, the Brunswick Unit 2 (BWR 4 with a Mark I containment), experienced an unplanned generator and turbine trip which occurred at 96 percent CLTP (approximately 115 percent OLTP) resulting in a reactor protection system actuation. As noted by the NRC staff in LER 2003-04, plant systems responded as designed to the transient and the event was fully bounded by the analyses in Chapter 15 of the UFSAR. On May 31, 2002, the NRC approved an EPU of 115 percent CLTP (approximately 120 percent OLTP) of 2923 MWt (Reference 197).

On January 30, 2004, the Dresden Nuclear Power Station, Unit 3 (BWR 3 with a Mark I containment), experienced an automatic scram due to a main turbine trip from low lube oil pressure while the plant was operating at 97 percent uprated power (approximately 113 percent OLTP). As discussed in LER 2004-002, all rods inserted and all systems responded as expected to the automatic scram. On December 21, 2001, the NRC approved an EPU of 117 percent OLTP of 2957 MWt for both units (Reference 198).

GGNS Plant-Specific Transient Operating Experience

Another factor used by Entergy to justify not performing Turbine Trip and Generator Load Rejection test (SU-27) were actual plant transients experienced at the GGNS. As documented in Attachment 9 of the EPU LAR, on March 21, 2008, while operating at uprated power level of 3898 MWt (100 percent CLTP; approx. 102 percent OLTP), the GGNS experienced a scram due to a generator load rejection event. The NRC staff review of LER 2008-002 identified that two of three turbine bypass valves promptly opened along with the actuation of six SRVs which limited peak steam dome pressure. Entergy concluded that all safety systems responded as designed.

Another factor used by Entergy to justify not performing test SU-27 is information and guidance contained in vendor topical reports, pursuant to Section III.C.2.f of SRP 14.2.1. Entergy stated in the EPU LAR that since the percent increase to CPPU for any GGNS event was less than 15 percent above any previously recorded generator load rejection transient (a thermal power increase of 13 percent above CLTP, 3898 MWt vs. 4408 MWt at full EPU power level), no new generator load rejection LTT (SU-27) is required, as recommended by guidance in vendor topical report Section 5.11.9, "Power Uprate Testing," and Appendix L.2.4, "Testing of Large Transient Disturbances," of GE LTR ELTR1. Previously recorded data may include unplanned as well as planned transients. Based on review of Entergy's justification discussed above, the NRC staff agrees with the basis for not performing SU-27. On October 10, 2002, the NRC approved a 1.7 percent uprate to operate at 3898 MWt (Reference 51).

Plant Transient Evaluation

The NRC staff reviewed the licensee's plant-specific assessment provided in Attachment 9 of the EPU LAR with respect to GGNS not performing certain large transient testing (e.g., MSIV-closure and generator load rejection test) similar to those conducted during the initial plant startup involving an automatic scram from a high power. Transient experience at high power and for a wide range of operating power levels at operating BWR plants, including other BWR/6 plants similar to GGNS, have shown an acceptable correlation of the plant transient data to the predicted response based on the NRC approved computer code ODYN. The operating history of GGNS demonstrates that previous transient events from full power are within expected peak limiting values. The transient analysis performed for the GGNS CPPU using ODYN demonstrated that all safety criteria are met and that this uprate did not cause any previous non-limiting events to become limiting (evaluated in Section 2.8.5 of this SE). Based on the similarity of plants, past transient testing, past analyses, and the evaluation of test results, the effects of the CPPU RTP level can be analytically determined on a plant-specific basis. No new design functions that would necessitate modifications and no large transient testing validation were required of safety related systems for the CPPU. The instrument setpoints that were changed do not contribute to the response to large transient events. No physical modification or setpoint changes were made to the SRVs. No new systems or features were installed for mitigation of rapid pressurization AOOs for this CPPU.

A scram from high power level results in an unnecessary and undesirable transient cycle on the primary system. Therefore, additional transient testing involving a scram from high power levels is not justifiable. Should any future large transients occur, GGNS procedures require identification of any anomalous plant response and verification that all key safety-related equipment, required to function during the event, operated as anticipated or expected. Existing plant event data recorders are capable of acquiring the necessary data to confirm the actual versus expected response. Transient mitigation capability is demonstrated by other tests required by the TS. In addition, the limiting transient analyses are included as part of the reload licensing analysis. The NRC staff concludes that the licensee's justification for not performing the MSIV-closure and the generator load rejection large transient tests, as discussed above, is acceptable based on the following considerations:

- Previous operating experience has demonstrated acceptable performance of SSCs under a variety of steady state and transient conditions;

- No new thermal-hydraulic phenomena or identified system interactions are expected to be introduced at the CPPU conditions. Because this EPU is a constant pressure power uprate, the effects on SSCs due to changes in thermal-hydraulic phenomena are limited;

- GGNS plant is in conformance with the limitations associated with applicable computer codes and analytical methods, such as ODYN;

- GGNS plant staff familiarization with facility operation and use of operating and emergency operating procedures; and

- Availability of adequate margin in safety analysis results for AOOs.

Conclusion

The NRC staff reviewed the licensee's EPU power ascension and testing program which included an evaluation of the licensee's plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance, the test program's conformance with applicable regulations, and the licensee's justification for not performing certain large transient tests as part of its PATP. Such justification included industry operating experience from other uprated BWRs, GGNS plant-specific transient operating experience at uprated power levels, and analytical evaluations and analysis of transient events.

The NRC staff concludes that GGNS's power ascension and testing program 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."

2.12.1.4 SRP 14.2.1, Section III.D, Evaluate the Adequacy of Proposed Transient Testing Plans

This section specifies the guidance and acceptance criteria the licensee should use to include plans for the initial approach to the increased EPU power level and testing that should be used to verify that the reactor plant operates within the values of EPU design parameters. The test plan should assure that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the design basis for the facility. The predicted testing responses and acceptance criteria should not be developed from values or plant conditions used for conservative evaluations of postulated accidents. During testing, safety-related SSCs relied upon during operation 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, flow rates, 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 NRC staff reviewed Attachment 9 to the EPU LAR which provided detailed information about startup testing using SRP 14.2.1 and Attachment 5A, "Safety Analysis Report for Grand Gulf Nuclear Station Constant Pressure Power Uprate," which provided a description of the required testing necessary for the initial power ascension following implementation of the EPU. The main elements of the PATP include power ascension, monitoring and analysis, and post-EPU monitoring. The NRC staff also determined that the licensee adequately addressed industry operating experience for similar designed BWR plants which have previously received an approved EPU from the NRC staff. The plants included Nine Mile Point 2, Clinton Power Station, and the River Bend Station.

As stated previously, the technical bases for the EPU request follows the guidelines contained in the following staff approved GENE LTRs for EPU safety analysis: NEDC-33004P-A, "Constant Pressure Power Uprate," (CLTR); NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1); and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2). PUSAR Section 2.12, "Power Ascension and Testing Plan," submitted with the licensee's application, provides additional information relative to power uprate testing and describes a standard set of tests which supplement the normal TS testing requirements established for the initial power ascension steps of CPPU. The test schedule would be performed in an incremental manner, with appropriate hold points for evaluation, and contingency plans would be utilized if predicted plant response is not obtained. The NRC staff concludes that all transient tests described in the initial startup test program were listed in Table 1 of Attachment 9. As discussed in Section 3.0 of Attachment 9, the following large transient tests were performed during initial plant startup: MSIV Functional Tests (SU-25A), performed at 84.2 percent OLTP (UFSAR Section 14.2.12.3.22.1); Full Reactor Isolation (SU-25B), performed at 75 percent OLTP (UFSAR Section 14.2.12.3.22.2); and a Turbine Trip and Generator Load Rejection test (SU-27), performed at 100 percent OLTP (UFSAR Section 14.2.12.3.24). These tests follow the tests described in Attachment 2 of SRP 14.2.1.

Conclusion

The NRC staff has reviewed the licensee's EPU PATP including its conformance with applicable regulations and the NRC staff guidance discussed in SRP 14.2.1. The NRC staff concludes that the proposed EPU test plan will adequately assure that the test objectives, test methods, and test acceptance criteria are consistent with the design basis for the facility. The NRC staff concludes that Entergy's power ascension and test program, and its justification for not performing large transient testing, is acceptable based on the applicable staff guidance and review criteria in Section III.C.2 of SRP 14.2.1, and the requirements of 10 CFR 50, Appendix B.

Overall Conclusion for Section 2.12.1

The NRC staff has reviewed the licensee's EPU power ascension and testing program, including plans for the initial approach to the proposed maximum licensed thermal power level, transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and the test program's conformance with applicable regulations. The review included an evaluation of the licensee's plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance, and the test program's conformance with applicable regulations. GGNS's test program primarily includes steady state testing with no large transient testing proposed. The NRC staff also reviewed the licensee's justification for not performing large transient testing as discussed in Attachment 9. The NRC staff concludes that the licensee's justification is acceptable based on the applicable review criteria discussed in Section III.C.2 of SRP 14.2.1.

Based on the above, the NRC staff concludes that the proposed EPU test program provides adequate assurance that the plant will operate as expected and in accordance with design criteria and that SSCs affected by the proposed EPU, or modified to support the proposed power increase, will perform satisfactorily in service. Further, the NRC staff concludes that there is reasonable assurance that the EPU testing program satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," and the NRC staff guidance and review criteria in SRP 14.2.1. Therefore, the NRC staff concludes that the proposed EPU is acceptable with respect to the power ascension and test program.

2.13 Risk Evaluation

2.13.1 Risk Evaluation of EPU

Regulatory Evaluation

The licensee did not request the relaxation of any deterministic requirements for its proposed power uprate, and the NRC staff's approval is primarily based on the licensee meeting the current deterministic engineering requirements. Per RS-001, Section 13 (Reference 54), a risk evaluation is conducted to determine if "special circumstances" are created by the proposed EPU. As described in Appendix D of SRP Section 19.2, "Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance" (Reference 62), 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 (Reference 54) and its attachments. Further guidance on how to make a determination of special circumstances is provided in Appendix D to SRP Section 19.2.

The NRC staff's review addresses the risk associated with operating at the proposed EPU conditions 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 NRC staff's review addresses the quality of the risk analyses used by the licensee to support the application for the proposed EPU. This includes a review of licensee actions to address issues or weaknesses that may have been raised in previous staff reviews of the licensee's individual plant examination (IPE), individual plant examinations of external events (IPEEE), or by industry peer reviews. The NRC staff used the guidance provided in NRC Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," November 2002 (Reference 199) and NRC Regulatory Guide (RG) 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities, Revision 1," January 2007 (Reference 200) to focus the review of this non-risk-informed submittal.

Technical Evaluation

The NRC staff reviewed the risk evaluation submitted for GGNS in the EPU LAR, as supplemented by responses to the NRC staff's RAI. The licensee has provided an estimate of the increase in risk (CDF and LERF) assuming EPU conditions. A combination of quantitative and qualitative methods was used to assess the risk impact of the proposed EPU. The following sections provide the NRC staff's technical evaluation of the risk information provided by the licensee. The NRC staff's evaluation did not involve an in-depth review of the licensee's risk evaluation but rather focused on the determination of special circumstances.

2.13.1.1 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 NRC 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 that would rebut the presumption of adequate protection.

2.13.1.1.1 IPE / IPEEE

The licensee submitted the GGNS Individual Plant Examination (IPE) to the NRC, which is based on a comprehensive and systematic plant analysis for Level 1 and Level 2 PRA performed on June 30, 1993, in fulfillment of NRC Generic Letter 88-20, "Individual Plant

Examination for Severe Accident Vulnerabilities – 10 CFR 50.54(f)," dated November 23, 1998 (Reference 201). On August 8, 1985, the NRC issued an SER stating that the licensee did not identify any plant vulnerabilities to severe accidents and cost effective safety improvements that could reduce or eliminate the impact of any such vulnerabilities. The IPE submittal identified changes to the plant, procedures, and training as part of the IPE process and the licensee has stated these changes have been incorporated into the PRA model.

As a result of performing the IPE, GGNS identified a number of modifications but considered only one for its cost-benefit analysis: Adding backup power supplies to the hydrogen igniters. GGNS determined that the "addition of power supplies [were] not cost-justified" at the time. In response to conference call regarding this issue, the licensee noted that it made a commitment to provide a portable power supply capable of powering the igniters in 2007. Per inspection report TI 2515/174, the NRC confirms that GGNS has met this commitment.

The licensee submitted the GGNS Individual Plant External Events Examination (IPEEE) to the NRC on November 15, 1995 (Reference 202), in response to Supplement 4 of GL 88-20 (Reference 201). On March 16, 2011 (Reference 203), the NRC issued an SER that concluded that the licensee's IPEEE identifies most likely severe accidents and severe accident vulnerabilities from external events. No outstanding issues were identified during NRC review of the GGNS IPEEE.

The licensee stated in its submittal, that all commitments resulting from the GGNS IPE and IPEEE Programs have been resolved.

Based on NRC staff review of dispositions of topics outstanding from the IPE and IPEEE assessment, the NRC staff concludes all items have been addressed appropriately and therefore do not impact the EPU risk assessment.

2.13.1.1.2 Peer Review of the GGNS PRA

The submittal stated that the GGNS internal events PRA received a formal industry peer review in August 1997. The peer review team used the "BWROG PSA Peer Review Certification Implementation Guidelines," Revision 3, January 1997. The licensee stated that all A (i.e., findings that are extremely important and necessary to address the technical adequacy of the PRA) and B (i.e., findings that are extremely important and necessary to address but that may be deferred until the next PRA update) priority peer review comments for all elements were addressed and incorporated into the PRA model after the peer review, except for one item related to internal flooding analysis and instrument air dependency, and nine elements related to Level 2 PRA.

The submittal notes that the Level 2 PRA previously used the EVENTRE software, whereas, the current GGNS LERF model is based on the CAFTA software. Based on this update the licensee addressed eight elements associated with "B" level findings related to Level 2 PRA. The remaining Level 2 element identifies failure to model vacuum breakers, low suppression pool level, and personnel hatch seal. The NRC staff agrees that explicit modeling of these failures would not significantly impact the delta risk results for the EPU application. The facts and observations (F&Os) related to instrument air dependency and flooding scenarios was delineated by the licensee to be included in the fault tree models used for the EPU risk assessment.

2.13.1.1.3 Conclusions Regarding the Quality of the GGNS 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 GGNS IPE and IPEEE; and reviewed the BWROG peer review open F&Os and their dispositions for this application.

Based on its evaluation, the NRC staff concludes that the GGNS 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.

2.13.1.2 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 GGNS PRA to determine the CDF and LERF of the post-EPU plant.

2.13.1.2.1 Initiating Event Frequencies

The GGNS PRA models include initiating event categories which encompass transient initiating events, LOCA initiators, loss of offsite power, and internal flooding initiators. The licensee's evaluation examined whether there may be increases in the frequency of initiating events as well as new types of initiating events.

Transients – Licensee stated that no planned changes were identified that would have a direct impact on transient frequency due to EPU. Sensitivity quantifications were performed that increase the Main Steam Isolation Valve (MSIV) closure and transient with Power Conversion System (PCS) available initiator frequencies to bound the various changes to the BOP side of the plant (e.g., main turbine modifications). Sensitivity analyses show that increased MSIV closure initiating event frequency produces delta CDF of 3.2E-7 and delta LERF of 1.56E-7. An additional turbine trip in the first year following EPU produces delta CDF of 3.5E-7 and delta LERF of 1.56E-07. Both sensitivities are within Region III ("very small changes in risk") of RG 1.174 risk guidelines and therefore acceptable.

Loss of Offsite Power (LOOP) – The licensee does not expect a change in LOOP initiating event frequency due to EPU. A grid stability analysis conducted by the licensee indicated no significant impacts on grid stability due to the GGNS power uprate.

Support System – Separate from the EPU, two additional service water pumps are being installed which will increase the number of service water pumps from eight to ten thus lowering the probability of service water system failure. The licensee stated 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) – No significant changes to reactor pressure vessel (RPV) operating pressure, inspection frequencies, or primary water chemistry are postulated for EPU, therefore; there is no significant impact on LOCA frequencies due to EPU. Since increased flow rates can result in increased piping erosion/corrosion rates, a sensitivity analysis doubled the large LOCA initiator frequency. By doubling the initiating event frequency for Large LOCAs, the delta risk results in 3.3E-7 and 8.0E-9 for CDF and LERF, respectively. Both of these results remain within Region III of RG 1.174 guidelines.

Internal Flooding – For internal flooding events, the licensee concluded that, other than as a consequence of the initiators discussed above that involve pipe breaks, there are no substantive changes to other systems that may induce internal flooding. Thus, the flooding initiator frequency is expected to remain unchanged.

2.13.1.2.2 Overall EPU Impact on Initiating Events

The NRC staff concludes that the licensee adequately addressed internal initiating event frequencies based on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Furthermore, short-term risk impact from break-in failures caused by the numerous BOP equipment changes is expected to be very small. Finally, the NRC 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 NRC staff concludes that there are no issues with the evaluation of internal initiating event frequencies associated with the GGNS internal events PRA and there is reasonable assurance of adequate protection concerning this risk. The expectation is that initiating event frequencies will not change as a result of the EPU.

2.13.1.2.3 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.

The NRC staff concludes 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 qualified by the increase in initiating event frequency. Finally, the NRC 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 NRC staff has not identified any issues associated with licensee's evaluation of component reliability that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with component reliabilities/failure rates modeled in the GGNS internal events PRA and there is reasonable assurance of adequate protection concerning this risk. The expectation is that there will be no change in component reliability as a result of the EPU.

2.13.1.2.4 Success Criteria

The licensee evaluated the impact of the proposed EPU on PRA accident sequence delineation and success criteria. The PRA success criteria are affected by the increased boil off rate, the increased heat load to the suppression pool, and the increase in containment pressure and temperature. The response to an initiator is represented in the PRA models by a set of discrete requirements for the operation of individual systems and the performance of specific operator actions. These scenario-specific requirements define the success criteria for system operation and operator action to fulfill the critical safety functions necessary to maintain the reactor fuel in a safe condition. The licensee assessed the critical safety functions and minimum system requirements to determine success for the following initiating event categories: general transients, Inadvertent Opened Relief Valve (IORV) or Transient with Stuck Open Relief Valve (SORV), Small LOCA, Intermediate LOCA, Large LOCA, anticipated transient without scram (ATWS), Internal Floods, interfacing system LOCA (ISLOCA), and break outside containment (BOC).

In response to RAI, the licensee addressed the limitations of the severe accident analysis tool, MAAP (Modular Accident Analysis Program). This software is utilized to evaluate success criteria for different accident scenarios. The licensee incorporated a work-around for MAAP Version 4.0.6 which involved two separate issues: 1) potential for an under-prediction of break flow in some LOCA analyses; and 2) incorrect containment response when the HPCI (High Pressure Coolant Injection) and/or RCIC (Reactor Core Isolation Cooling) turbine systems are operating. MAAP version 4.0.6 and the associated work around were applied to both pre-EPU and EPU models.

One success criteria impact due to EPU was identified for the Level 1 PRA:

> 15 of 20 SRVs are required for the EPU condition for RPV initial overpressure protection during an ATWS scenario (as opposed to 13 of 20 for the current condition).

The licensee stated that this change is addressed in the GGNS EPU risk assessment.

The SRV setpoints were not changed as a result of the EPU; however, the base probability of a stuck-open SRV due to additional cycling was increased in the GGNS PRA by 13 percent by using the conservative upper bound approach of increasing SRV probability by a factor equal to the increase in reactor power. The approach assumes that the stuck open relief valve probability is linearly related to the number of SRV cycles, and that the number of SRV cycles is linearly related to the reactor power increase. Two additional less conservative approaches were also considered by the licensee: one that considered the number of cycles having a non linear relationship to reactor power increase and another that assumed the stuck open relief valve probability is dominated by the initial cycle and that subsequent cycles have a much lower failure rate.

Timing changes have been identified for the level 1 PRA and can impact human error probabilities (HEPs) for operator actions. This change has been factored into revised HEP values for EPU conditions as described in the section on human reliability analysis (HRA).

The licensee noted a negligible impact on the level 2 PRA safety functions and results and concluded that no changes to the success criteria have been identified with regard to the level 2 containment evaluation.

2.13.1.2.4.1 Overall EPU Impact on Accident Sequence Delineation and Success Criteria

The NRC staff agrees with the licensee's changes to the accident sequence delineation and success criteria made to reflect the post-EPU plants.

2.13.1.2.5 Operator Actions and LOOP Recovery

Human Reliability Analysis – 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. GGNS has no new operator actions or operator workarounds created as a result of the EPU.

The success of these operating crew actions are dependent on a number of performance-shaping factors which are principally influenced by the time available to detect, diagnose, and perform required actions. The higher power level results in reduced times available for some operator actions.

All post-initiator operator actions included in the GGNS PRA were evaluated for potential effects resulting from the EPU. Sixty-two human error probabilities (HEP) were identified as having an impact from the increased power levels and/or reduced timing by the EPU. GGNS stated that all operator actions which could be affected by changes in reactor power or other parameters affected by the EPU were analyzed.

For operator actions that the licensee identified as having the potential to be significantly impacted by the EPU, a HRA was performed. The GGNS PRA Human Reliability Analysis utilizes two methods to calculate the HEP probabilities: Human Cognitive Reliability / Operator Reliability Experiment (HCR/ORE) correlation and the Caused-Based Decision Tree (CBDT) Approach. The method that produced more conservative results for each individual human error probability was employed in the analysis. The CBDT method is influenced by changes in operator action timing over wider time frames than the HCR/ORE method. Since the delta risk of extended power uprates are largely dependent on decreases in allowable operator action times, in response to RAI, the licensee calculated all human error probabilities using the

HCR/ORE method for both pre-EPU and EPU conditions. As shown in Table 2.13.1.2.5-1 below, the total CDF and total LERF results are lower than the original analysis performed by using both methods. The delta risk; however, was slightly higher but within Region III of RG 1.174 guidelines.

Table 2.13.1.2.5-1. Results Comparing Base PRA HEP Approach and HCR/ORE Method

Plant Configuration	CDF – Base PRA Approach	LERF – Base PRA Approach	CDF – HCR/ORE Method	LERF – HCR/ORE Method
Pre-EPU	2.68E-06	1.44E-07	2.29E-06	1.07E-07
EPU	2.91E-06	1.48E-07	2.76E-06	1.34E-07
Delta Risk	2.30E-07	4.30E-09	4.71E-07	2.73E-08

Knowledge of the context surrounding each of the modeled operator actions (e.g., the sequences that are addressed and the additional equipment failures that have occurred) is important to ensure that the correct HEPs have been assigned. The NRC staff agrees with the licensee's conclusion that the main impact of the proposed EPU on the post-initiator operator actions is the reduction in time available for the plant operators to detect, diagnose, and perform required actions.

The licensee's use of thermal hydraulic analyses and knowledge of equipment capacities to determine the change in the time available for diagnosis and decision-making for the post-initiator operator actions is consistent with good PRA practices. The NRC staff observes that the apparent small changes in available times, and the corresponding changes in the post-initiator HEP values, should not be taken literally since the parameters and models used to obtain them are uncertain.

2.13.1.2.5.1 Overall EPU Impact on Operator Actions

Based on the above, the NRC staff concludes 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 GGNS internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment.

2.13.1.2.6 Internal Events Risk Results

Level 1 PRA estimates the frequency of core damage for different initiating events that have the potential to occur at the plant. The impact of increases in initiating event frequencies was presented as sensitivity studies in the application and the outcome of these studies show negligible increases in core damage frequency.

Level 2 PRA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. The simplified Level 2 evaluation calculates the LERF using CDF accident sequences and bins results into LERF, intact containment, late containment failure and small early release end states. The licensee stated that the calculations considered all relevant severe accident phenomenology.

Table 2.13.1.2.5.1-1. Internal Events CDF and LERF Risk Metrics

	Pre EPU Base Model	Post EPU	Change	Percent Increase
CDF	2.68E-06	2.91E-06	2.3E-07	8.6%
LERF	1.44E-07	1.48E-07	4.3E-09	3.0%

The increases in internal events CDF and LERF, shown in Table 2.13.1.2.5-1 falls within the RG 1.174 acceptance guidelines for being "very small" and therefore does not raise concerns of adequate protection.

The NRC staff concludes that the licensee's evaluation of the impact of the proposed EPU on at-power risk from internal events provides reasonable assurance of adequate protection concerning this risk and that the base risk due to the proposed EPU is acceptable.

2.13.1.3 External Events Risk Evaluation

The licensee has a limited seismic and fire PRA model. The IPEEE studies used the Electric Power Research Institute (EPRI) Fire Induced Vulnerability Evaluation (FIVE) methodology and a seismic margins assessment (SMA) to address external risk from these sources. 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.

2.13.1.3.1 Internal Fire Risk

For the IPEEE fire analysis, GGNS performed a fire PRA by implementing the FIVE methodology. The IPEEE staff evaluation notes the licensee analyzed all fire areas and compartments using a reasonable screening methodology. The fire risk evaluation using the EPRI FIVE methodology estimated a fire-induced CDF of 8.76E-06 per year.

In response to RAI, the licensee explained that the fire PRA model used in the GGNS EPU risk assessment is based on the GGNS IPEEE fire analysis and a previous version (2004) of the GGNS system fault tree and accident sequence structures. An update of the GGNS IPEEE fire model for integration with the latest GGNS PRA revision was not performed as part of the GGNS EPU risk assessment. The NRC staff does not expect the use of a prior PRA model to significantly impact the delta risk due to fire for this application. The fire PRA model was rerun for this EPU risk assessment using the same changes incorporated into the internal events PRA. The GGNS fire PRA models approximately 125 fire scenario initiators. The results of the changes to the GGNS fire PRA due to the reduced timings available show an increase of 3 percent in the fire CDF.

Fire frequencies and fire mitigation are not related to reactor power level and the licensee proposed modifications to reduce fire risk, therefore the NRC staff does not expect the post-EPU risk increase due to fire to exceed RG 1.174 guidelines and create the "special circumstances" described in Appendix D of SRP Section 19.2, "Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance," for a non risk-informed application.

2.13.1.3.2 Seismic Risk

The GGNS seismic risk analysis was performed as part of the IPEEE. Given the GGNS seismic design basis and the comparably low seismic hazard at the site, NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991 (Reference 204), placed GGNS in the Reduced Scope Review Level Earthquake IPEEE seismic category. More recently, an August 2010 report, "Generic Issue 199 (GI-199), Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants" (Reference 205), shows a decrease in GGNS seismic CDF using 2008 United States Geological Survey (USGS) seismic hazards curve when compared against 1994 Lawrence Livermore National Lab Hazard Curves. Based on a simplified approach to estimate the core damage frequency from a seismic margins analysis and using the latest published USGS seismic hazards information, the NRC staff estimates the GGNS seismic CDF is about or slightly less than 1E-5/year.

The EPU results in additional thermal energy stored in the reactor pressure vessel (RPV), but the additional blowdown loads on the RPV and containment given a coincident seismic event are judged not to alter the results of the SMA. The decrease in time available for operator actions, and the associated increases in calculated HEPs is judged not have a significant impact on seismic-induced risk. As such, the NRC staff does not expect the seismic risk associated with the plant to rebut the presumption of adequate protection. For a risk-informed submittal, the NRC staff would have investigated further the impact of seismic risk; however, for a non risk-informed submittal, the NRC 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 Section 19.2.

2.13.1.3.3 Other External Events Risk

The GGNS IPEEE addresses events other than seismic and fires, including high winds/tornadoes, 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 GGNS meets the applicable NRC SRP requirements and, therefore, has an acceptably low risk with respect to these hazards.

2.13.1.3.4 External Events Risk Conclusion

The NRC 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 is reasonable assurance of adequate protection concerning risk from external events. 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.

2.13.1.4 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. The aspects of shutdown risk that the licensee identified as being impacted by EPU conditions included greater decay heat generation, longer times to shutdown, shorter times to boiling, and shorter times for operator responses. All of these aspects result from the increased decay heat generation created by the EPU. The increased power level decreases the boildown time. However, because the reactor is already shut down, the boildown times are relatively long compared to the at-power PRA.

The licensee stated procedural controls are in place to ensure the risk impacts of EPU on shutdown operations are not significant and that requirements of NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," December 1991 (Reference 206), are implemented to assure risk is assessed and that structures, systems, and components that perform key safety functions are available when needed.

During EPU implementation outages, modifications to systems and installation of new equipment will be controlled as described above to ensure risk management requirements are satisfied. The GGNS modification process ensures that the modifications and new equipment are incorporated into the shutdown safety assessment procedure for consideration in future outages.

The increase in decay heat for EPU will potentially result in a reduced required time to perform containment closure. Plant shutdown emergency procedures contain time to boil curves. These curves will be updated for EPU conditions. Shutdown safety review and safety assessment processes provides guidance for ensuring containment closure can be completed within the required time, as part of outage risk assessment.

Based on review of the potential impacts on initiating events, success criteria, and HRA the EPU is assessed to have a negligible impact on shutdown risk. The licensee approximates two percent per calculations in Appendix B.

The NRC 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 that there is reasonable assurance of adequate protection concerning this risk. 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 concludes that there are no issues with the licensee's risk evaluation for the proposed EPU that would create the "special circumstances" described in Appendix D of SRP Chapter 19, "Severe Accidents." Therefore, the NRC staff concludes that the risk implications of the proposed EPU are acceptable.

3.0 FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION CHANGES

To achieve the EPU, the licensee proposed the following changes to the Facility Operating License and TSs for GGNS.

3.1 Proposed License Conditions

3.1.1 Change on Power Level: Revised License Conditions 2.C.(1) and 2.C.(2)

In the EPU LAR (Reference 1), the licensee proposed to revise paragraph 2.C.(1) of Facility Operating License No. NPF-29 to change the maximum reactor core power level from 3898 MWt to 4408 MWt and paragraph 2.C.(2) to indicate changes to the TSs through Amendment No. 191. Accordingly, paragraphs 2.C.(1) and 2.C.(2) of Facility Operating License No. NPF-29 would be revised to state:

(1) Maximum Power Level

Entergy Operations, Inc. is authorized to operate the facility at reactor core power levels not in excess of 4408 megawatts thermal (100 percent power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 191 are hereby incorporated into this license. Entergy Operations, Inc. shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

During Cycle 19, GGNS will conduct monitoring of the Oscillation Power Range Monitor (OPRM). During this time, the OPRM Upscale function (Function 2.f of Technical Specification Table 3.3.1.1-1) will be disabled and operated in an "indicate only" mode and technical specification requirements will not apply to this function. During such time, Backup Stability Protection measures will be implemented via GGNS procedures to provide an alternate method to detect and suppress reactor core thermal hydraulic instability oscillations. Once monitoring has been successfully completed, the OPRM Upscale function will be enabled and technical specification requirements will be applied to the function; no further operating with this function in an "indicate only" mode will be conducted.

NRC Staff Evaluation

This change is administrative in nature as it reflects the approval of the EPU provided by this SE.

3.1.2 Leak Rate Test: New License Condition 2.C.(44)

In the EPU LAR (Reference 1), the licensee proposed to add the following new license condition. Accordingly, Facility Operating License No. NPF-29 would be revised to add new paragraph 2.C.(44), which would state:

> (44) Leak rate tests associated with Surveillance Requirements (SR) 3.6.1.1.1, 3.6.1.3.5, and 3.6.1.3.9, as required by TS 5.5.12 and in accordance with 10 CFR 50, Appendix J, Option B, and SRs 3.6.5.1.1 and 3.6.5.1.2 are not required to be performed until their next scheduled performance dates. The tests will be performed at the EPU calculated long-term peak containment pressure or within EPU drywell bypass leakage limits, as appropriate.

By letter dated September 9, 2011 (Reference 28), the licensee revised the proposed license condition 2.C.(44) to delete "long-term" from the phrase "EPU calculated long-term peak containment pressure." Accordingly, Facility Operating License No. NPF-29 would be revised to add new paragraph 2.C.(44), which would state:

> (44) Leak rate tests associated with Surveillance Requirements (SR) 3.6.1.1.1, 3.6.1.3.5, and 3.6.1.3.9, as required by TS 5.5.12 and in accordance with 10 CFR 50, Appendix J, Option B, and SRs 3.6.5.1.1 and 3.6.5.1.2 are not required to be performed until their next scheduled performance dates. The tests will be performed at the EPU calculated peak containment pressure or within EPU drywell bypass leakage limits, as appropriate.

NRC Staff Evaluation

10 CFR Appendix J Leak Rate Testing

By letter dated September 9, 2011 (Reference 28), the licensee revised the proposed license condition (paragraph 2.C.(44) of NPF-29) to delete "long-term" from the phrase "EPU calculated long-term peak containment pressure" and to add the following sentence to TS 5.5.12:

> The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is 14.8 psig.

These changes were made as result of the NRC staff conclusion that the licensee's interpretation of "long-term peak containment pressure" was inconsistent with the Appendix J criteria. As such, the licensee proposed to perform the 10 CFR 50 Appendix J testing per TS SRs 3.6.1.1.1, 3.6.1.3.5, and 3.6.1.3.9 at the revised value of P_a (14.8 psig) at the next scheduled test date instead of at the time of EPU implementation. The licensee justified this proposal by an evaluation (Reference 207) demonstrating that the leakage test results based on a former P_a (11.5 psig) would still be expected to satisfy the appropriate acceptance criteria when tested at the EPU value of P_a (14.8 psig). The NRC staff considers the evaluation acceptable because the licensee has shown that the predicted leakages at the EPU value of P_a of 14.8 psig are bounded by the acceptable leakage limits per 10 CFR 50 Appendix J. The NRC staff therefore considers it acceptable for the licensee to perform the above SR tests at the next scheduled date.

Drywell-to-Wetwell Steam Bypass Capability Testing

The licensee proposed to perform the TS SRs 3.6.5.1.1 and 3.6.5.1.2 at the next scheduled date instead of at the time of EPU implementation. SR 3.6.5.1.1 requires verification of the drywell-to-wetwell bypass leakage is less than or equal to the bypass leakage limit. The licensee has revised the steam bypass effective area capability ($A/\sqrt{K}$) from its current licensing basis value of 0.9 ft^2 to 0.8 ft^2 for EPU. The licensee justifies this proposal stating (Reference 204) that in the previous test results the value of ($A/\sqrt{K}$) was determined to be 0.019 ft^2 demonstrating sufficient margin exists. The licensee stated that performance of visual inspection of the drywell exposed accessible interior and exterior surfaces per SR 3.6.5.1.2 has the same schedule as SR 3.6.5.1.1. The NRC staff considers it acceptable for the licensee to perform SRs 3.6.5.1.1 and 3.6.5.1.2 at their next schedule date instead of at EPU implementation because there is sufficient margin between leakage factor test result and its EPU value of 0.8 and it is reasonable to perform both SRs together.

The licensee has stated the new value for P_a will be used for the Appendix J Type B and C test during the spring 2012 refueling outage prior to the EPU approval.

3.1.3 Power Level: New License Condition 2.C.(45)

In the EPU LAR (Reference 1), the licensee proposed to add the following new license condition. Accordingly, Facility Operating License No. NPF-29 would be revised to add new paragraph 2.C.(45), which would state:

> (45) EOI will not operate GGNS at a thermal power level above 3,898 MWt until the Power Range Neutron Monitoring System license amendment request is approved by the NRC.

<u>NRC Staff Evaluation</u>

The PRNMS was approved by the NRC staff by Amendment No. 188 issued on March 28, 2012 and therefore, the license condition has been met. As such by letter dated April 26, 2012, the licensee proposed to withdraw this license condition and the NRC staff agrees that this license condition is no longer needed.

3.1.4 Spent Fuel Pool: New License Condition 2.C.(45)

By letter dated September 9, 2011 (Reference 28), the licensee proposed to add the following new license condition. Accordingly, Facility Operating License No. NPF-29 would be revised to add new paragraph 2.C.(45), which would state:

(45) Through Cycle 19 or until the revised criticality safety analysis has been approved, whichever comes first, the storage cells in the GGNS SFP racks shall be categorized as either Unrestricted or Restricted.

(a) Unrestricted cells (Region I) are cells with a minimum panel B10 areal density greater than 0.0179 gm/cm^2 and that have received an exposure less than 2.3E10 rads. Unrestricted cells may contain fuel assemblies up to the maximum k-infinity of 1.26 (cold core configuration).

(b) Restricted cells (Region II) are cells with either a minimum panel B10 areal density less than 0.0179 gm/cm^2 or that have received an exposure in excess of 2.3E10 rads. Storage in Restricted cells shall not credit any Boraflex. Storage shall be controlled in a 10 of 16 configuration (see below). In addition, only fuel assemblies with a k-infinity of less than 1.21 (cold core configuration) may be stored in a Region II cell.

Region II 4X4 Storage Configuration

	B		B
B			
	B		B
		B	

	Fuel Assembly Storage Location
B	Location Physically Blocked to Prevent Storage

NRC Staff Evaluation

See Section 2.8.6.2 for the basis for the approval of this license condition. The licensee has stated this license condition has been implemented during the spring 2012 refueling outage prior to the EPU approval.

3.1.5 Steam Dryer Power Ascension Testing: New License Condition 2.C.(46)

By letter dated April 18, 2012 (Reference 46), as supplemented by letter dated April 26, 2012 (Reference 47), the licensee proposed to add the following new license condition. Accordingly, Facility Operating License No. NPF-29 would be revised to add new paragraph 2.C.(46), which would state:

(46) This license condition provides for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant structures, systems, and components (including verifying the continued structural integrity of the steam dryer) for power ascension from the CLTP (3898 MWt) to the EPU level of 4408 MWt (or 113 percent of CLTP or 115 percent of OLTP).

(a) The following requirements are placed on operation of the facility before and during the power ascension to 3898 MWt:

1. GGNS shall provide a Power Ascension Test (PAT) Plan for the Steam Dryer testing. This plan shall include:

- Criteria for comparison and evaluation of projected strain and acceleration with on-dryer instrument data.

- Acceptance limits developed for each on-dryer strain gage and accelerometer.

- Tables of predicted dryer stresses at CLTP, strain amplitudes and PSDs at strain gage locations, acceleration amplitudes and PSDs at accelerometer locations, and maximum stresses and locations.

The PAT plan shall provide correlations between measured accelerations and strains and the corresponding maximum stresses. The PAT plan shall be submitted to the NRC Project Manager no later than 10 days before start-up.

2. GGNS shall monitor the main steam line (MSL) strain gages and on-dryer instrumentation at a minimum of three power levels up to 3898 MWt. Based on a comparison of projected and measured strains and accelerations, GGNS will assess whether the dryer acoustic and structural models have adequately captured the response significant to peak stress projections. If the measured strains and accelerations are not within the CLTP acceptance limits, the new measured data will be used to re-perform the full

structural re-analysis for the purposes of generating modified EPU acceptance limits.

3. GGNS shall provide a summary of the data and evaluation of predicted and measured pressures, strains, and accelerations. This data will include the GGNS-specific bias and uncertainty data and transfer function, revised peak stress table and any revised acceptance limits. The predicted pressures shall include those using both PBLE methods (that is, Method 1 using on-dryer data, and Method 2 using MSL data). It shall be provided to the NRC Project Manager upon completion of the evaluation. GGNS shall not increase power above 3898 MWt until the NRC PM notifies GGNS the NRC accepts the evaluation or NRC questions regarding the evaluation have been addressed. If no questions are identified within 240 hours after the NRC receives the evaluation, power ascension may continue.

(b) The following requirements are placed on operation of the facility during the initial power ascension from 3898 MWt to the approved EPU level (4408 MWt):

1. GGNS shall increase power in increments of approximately 102 MWt, hold the facility at approximately steady state conditions and collect data from available main steam line (MSL) strain gages and available on-dryer instrumentation. This data will be evaluated, including the comparison of measured dryer strains and accelerations to acceptance limits and the comparison of predicted dryer loads based on MSL strain gage data to acceptance limits. It will also be used to trend and project loads at the next test point and to EPU conditions to demonstrate margin for continued power ascension.

2. Following the data collection and evaluation at the plateaus at approximately 4102 MWt, 4306 MWt, and 4408 MWt, GGNS shall provide a summary of the data and the evaluation performed in Section b.1 above to the NRC Project Manager. GGNS shall not increase power above these power levels for up to 96 hours to allow for NRC review of the information.

3. Should the measured strains and accelerations on the dryer exceed the level 1 acceptance limits, or alternatively if the dryer instrumentation is not available and the projected load on the dryer from the MSL strain gage data exceeds the Level 1 acceptance limits, GGNS shall return

the facility to a power level at which the limits are not exceeded. GGNS shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to the NRC Project Manager prior to further increases in reactor power. GGNS shall not increase power for up to 96 hours to allow for NRC review of the information.

a. In the event that acoustic signals (in MSL strain gage signals) are identified that challenge the dryer acceptance limits during power ascension above 3898 MWt, GGNS shall evaluate dryer loads, and stresses, including the effect of ±10 percent frequency shift, and re-establish the acceptance limits and determine whether there is margin for continued power ascension.

b. During power ascension above 3898 MWt, if an engineering evaluation for the steam dryer is required because a Level 1 acceptance limit is exceeded, GGNS shall perform the structural analysis using the Steam Dryer Report, Appendix A methods to address frequency uncertainties up to ±10% and assure that peak responses that fall within this uncertainty band are addressed.

4. Following the data collection and evaluation at the EPU power level, GGNS shall provide a final load definition and stress report of the steam dryer, including the results of a complete re-analysis using the GGNS-specific bias and uncertainties and transfer function. The GGNS-specific bias and uncertainties summary shall include both PBLE Method 1 and Method 2. This report shall be transmitted to the NRC within 90 days of achieving the EPU power level. Should the results of this stress analysis indicate the allowable stress in any part of the dryer is exceeded, GGNS shall reduce power to a level at which the allowable stress is met, evaluate the dryer integrity, and assess any shortcomings in the predictive analysis. The results of this evaluation, including a recommended resolution of any identified issues and a demonstration of dryer integrity at EPU conditions, shall be provided to the NRC prior to return to EPU conditions.

(c) Entergy shall implement the following actions:

1. Entergy shall revise the post-EPU monitoring and inspection program to reflect long-term monitoring of plant parameters potentially indicative of steam dryer failure; to reflect consistency of the facility's steam dryer inspection program with GE SIL 644, "BWR Steam Dryer Failure," Revision 2; and with BWRVIP-139, "Steam Dryer Inspection and Flaw Evaluation Guidelines."

(d) Entergy shall prepare the EPU PAT plan to include the following and provide it to the NRC project manager before increasing power above 3898 MWt:

1. Level 1 and Level 2 acceptance limits for on-dryer strain gages, on-dryer accelerometers, and for projected dryer loads from MSL strain gage data to be used up to 113 percent of CLTP
2. specific hold points and their duration during EPU power ascension
3. activities to be accomplished during hold points
4. plant parameters to be monitored
5. inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points
6. methods to be used to trend plant parameters
7. acceptance criteria for monitoring and trending plant parameters and conducting the walkdowns and inspections
8. actions to be taken if acceptance criteria are not satisfied
9. verification of the completion of commitments and planned actions specified in the Entergy application and all supplements to the application in support of the EPU LAR pertaining to the steam dryer before power increase above 3898 MWt
10. identify the NRC PM as the NRC point of contact for providing PAT plan information during power ascension
11. methodology for updating limit curves

(e) The key attributes of the PAT Plan shall not be made less restrictive without prior NRC approval. Changes to other aspects of the PAT Plan may be made in accordance with the guidance of NEI 99-04, "Guidelines for Managing NRC Commitments," issued July 1999.

(f) During the first two scheduled refueling outages after reaching full EPU conditions, Entergy shall conduct a visual inspection of all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 and GE inspection guidelines. Entergy shall report the results of the visual inspections of the steam dryer to the NRC staff within 60 days following startup.

(g) At the end of the second refueling outage, following the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results for NRC review and approval

(h) This license condition shall expire upon satisfaction of the requirements in paragraph (f) provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw or unacceptable flaw growth that is caused by fatigue.

NRC Staff Evaluation

See Section 2.2.6.6 for the basis for the approval of this license condition. The licensee has stated this license condition will be implemented after the EPU approval.

3.1.6 Conclusion

The NRC staff concludes that the proposed new and revised license conditions are acceptable and will provide assurances that the implementation of the EPU will maintain the current licensing basis of the GGNS.

3.2 Proposed TS Changes

3.2.1 TS Values Re-scaled to Reflect EPU (TS 2.1.1.1, TS 3.2.1, TS 3.2.2, TS 3.2.3, and TS 3.3.1.1, Including TS Table 3.3.1.1-1)

The following TS values were re-scaled to reflect the increased RTP level as result of the EPU.

TS Section	LAR Attachment 1 Discussion	TS Change	SE Section
TS 2.1.1.1	4.1.5	25% re-scaled to 21.8%	2.8.2
TS 3.2.1	4.1.7	25% re-scaled to 21.8%	2.8.2
TS 3.2.2	4.1.8	25% re-scaled to 21.8%	2.8.2
TS 3.2.3	4.1.9	25% re-scaled to 21.8%	2.8.2
TS 3.3.1.1, Required Action E	4.1.10	40% re-scaled to 35.4%	2.4.1.4 (1)a
TS 3.3.1.1, Required Action F	4.1.10	25% re-scaled to 21.8%	2.4.1.4 (1)b
TS 3.3.1.1, Required Action K	4.1.10	24% re-scaled to 21%	2.1.4.1 (1)c
SR 3.3.1.1.2	4.1.10	25% re-scaled to 21.8%	2.4.1.4 (2)
SR 3.3.1.1.14	4.1.10	40% re-scaled to 35.4%	2.4.1.4 (3)
SR 3.3.1.1.23	4.1.10	29% re-scaled to 26%	2.4.1.4 (4)
Table 3.3.1.1-1, Function 2.d, footnote (b)	4.1.10	Two-loop operation: 0.65W +62.9% RTP re-scaled to 0.58W + 59.1% RTP	2.4.1.4 (6)
		Single-loop operation: 0.65W +42.3% RTP re-scaled to 0.58W + 37.4% RTP	2.4.1.4 (6)
Table 3.3.1.1-1, Function 2.f	4.1.10	24% re-scaled to 21%	2.4.1.4 (7)
Table 3.3.1.1-1, Function 5	4.1.10	25% re-scaled to 21.8%	2.4.1.4 (8)
Table 3.3.1.1-1, Function 9	4.1.10	40% re-scaled to 35.4%	2.4.1.4 (9)
Table 3.3.1.1-1, Function 10	4.1.10	40% re-scaled to 35.4%	2.4.1.4 (10)
TS 3.3.4.1	4.1.11	40% re-scaled to 35.4%	2.4.1.4 (11)
SR 3.4.3.1	4.1.13	25% re-scaled to 21.8%	2.8.2

The licensee has re-scaled the TS values of percentage of RTP to maintain the current value in terms of absolute thermal power or margin to the fuel thermal limits (25 percent to 21.8 percent). The only exceptions are for TS 3.3.1.1 Required Action K and Table 3.3.1.1-1, Function 2.f;

these values are adjusted to maintain a margin of 5 percent to the re-scaled OPRM trip enabled region. These changes have been evaluated in the noted sections of this SE and, therefore, the NRC staff concludes that these changes are acceptable.

3.2.2 TS Values Revised to Maintain Margin (TS Table 3.3.1.1-1)

The following TS values were revised to maintain margin:

TS Section	LAR Attachment 1 Discussion	TS Change	SE Section
Table 3.3.1.1-1, Function 2.b	4.1.10	Allowable value revised from 120% to 119.3%	2.4.1.3.2
Table 3.3.6.1.-1, Function 1.c	4.1.12	Allowable value revised from 176.5 psid to 255.9 psid	2.4.1.3.1

The NRC staff's review of these TS changes is provided in the noted SE sections above. Based on the above, the NRC staff concludes that these changes are acceptable.

3.2.3 Definitions – Rated Thermal Power (TS 1.1)

With the approval of the EPU the RTP in TS 1.1, "Definitions," will be revised from 3898 MWt to 4408 MWt. As such, this is an administrative change and the NRC staff concludes it is acceptable.

3.2.4 Definitions – Pressure and Temperature Limits Report (TS 1.1)

As part of the LAR, the licensee has proposed revisions to TS 1.1, "Definitions," to implement TSTF 419-A, "Revise PTLR Definition and References in ISTS 5.6.6, RCS PTLR." The approval of this TSTF is discussed in Section 2.1.8 of the SE. Accordingly, TS 1.1, Definitions," would be revised to add a new definition for the PTLR, which would state:

> PRESSURE TEMPERATURE LIMITS REPORT (PTLR)
>
> The PTLR is the unit-specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6.

3.2.5 Thermal Power Limit with Low Dome Pressure or Core Flow (TS 2.1.1.1 and TS 2.1.1.2)

In March 2005, GE Energy–Nuclear issued a 10 CFR Part 21 communication regarding the potential for BWRs to experience reactor pressure below the low pressure Safety Limit of 785 psig defined in TS 2.1.1.1 under certain transient conditions. As documented in Safety Communication 05-03, "Potential to Exceed Low Pressure Technical Specification Safety Limit," depressurization transients, such as the Pressure Regulator Failure-Maximum Demand Open

(PRFO), could cause the reactor steam dome pressure to decrease to below 785 psig for a few seconds while thermal power exceeds 25 percent of rated power.

In July 2006, the BWROG proposed to address this issue with a change to the Technical Specification Bases (TSTF-495) indicating that TS 2.1.1.1 is not applicable to depressurization transients, such as PRFO, that may result in momentarily decreasing below 785 psig with power above 25 percent. The NRC subsequently rejected this proposed TSTF indicating that the TS Bases is not the appropriate location for an exception to an explicit safety limit.

To facilitate the closure of this issue, Entergy proposed a change to TS 2.1.1.1 to reduce steam dome pressure from 785 psig to 685 psig, thereby significantly reducing the likelihood of a depressurization transient resulting in a power-pressure profile that exceeds the safety limit in TS 2.1.1.1. The reduction in dome pressure is consistent with that used in the NRC-approved critical power correlations for the GE14 and GNF2 fuel designs:

- NEDC-32851P-A, Rev. 4, GEXL14 Correlation for GE14 Fuel
- NEDC-33292P-A, Rev. 3, GEXL17 Correlation for GNF2 Fuel

The steam dome pressure in TS 2.1.1.1 and the steam dome pressure listed in TS 2.1.1.2 will be revised to 685 psig. The proposed changes are based on NRC-approved topical reports and are, therefore, acceptable.

3.2.6 Standby Liquid Control System (SLC) (TS 3.1.7)

By letter dated January 23, 2012 (Reference 208), the licensee withdrew this request from the EPU LAR and submitted it as a separate LAR. This LAR was approved by the NRC staff by Amendment No. 190 dated May 11, 2012 (Reference 209).

3.2.7 Safety Relief Valves (SRVs) (TS 3.4.3)

The current LCO requires that seven SRVs be operable. The proposed change will require that nine SRVs be operable. The basis for the new S/RV requirements is the ATWS event closure of all main steam line isolation valves (MSIVC). The proposed change increases the total number of required SRVs from 13 to 15 to ensure reactor pressure remains below the ASME Service Level C limit of 120 percent of vessel design pressure (120% x 1250 psig = 1500 psig) during the most limiting ATWS event. Refer to PUSAR Section 2.8.5.7.1 and Table 2.8-8. The NRC staff has reviewed the ATWS events in Section 2.8.5.7 assuming five SRVs out-of-service (OOS) at EPU conditions. The NRC staff has concluded that the licensee has adequately accounted for the effects of the proposed EPU on ATWS events and the TS change is acceptable.

3.2.8 Changes RCS Pressure and Temperature *(P/T) Limits (TS 3.4.11) and New TS 5.5.6, "Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)"

Entergy stated that evaluations performed in support of EPU identified that the P/T limits need to be changed. As part of this LAR, Entergy proposed to implement TSTF-419-A and adopt the new limits in a PTLR. Along with the incorporation of the new curves, Entergy proposed the deletion of Figure 3.4.11-1, the P/T limits curves, based on the creation of the PTLR. NRC Generic Letter (GL) 96-03, "Relocation of the Pressure Temperature Limit Curves and Low Temperature Overpressure Protection System Limits" (Reference 89), provides guidance that allows the relocation of the RCS P/T curves to a PTLR. The proposed PTLR adopts the methodology described in NRC-approved NEDC-33178P-A, Revision 1, "GE Hitachi Nuclear Energy Methodology for Development of Reactor Pressure Vessel Pressure Temperature Curves" (Reference 90), for preparation of the P/T curves. The following changes are required to support the relocation of the P/T curves to the PTLR:

- LCO 3.4.11 currently states: "RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation loop temperature requirements shall be maintained within limits." To clarify the relocation of the limits to the PTLR, the LCO will be modified to state that the requirements shall be maintained within "...the limits specified in the PTLR."

- Actions A.1 and C.1 require restoration of the parameters to within limits. To clarify the relocation of the limits to the PTLR, the Actions will be modified to state "...within the limits specified in the PTLR."

- SR 3.4.11.1 a – "within the limits of the applicable Figure 3.4.11-1" will be replaced with "within the limits specified in the PTLR."

- SR 3.4.11.1 b – "≤ 100°F in any 1 hour period," will be replaced with "within the limits specified in the PTLR."

- SR 3.4.11.2 - "... in the applicable Figure 3.4.11-1" will be replaced with "... in the PTLR."

- SR 3.4.11.3 – "≤ 100°F" will be replaced with "within the limits specified in the PTLR."

- SR 3.4.11.4 – "≤ 50°F" will be replaced with "within the limits specified in the PTLR."

- SRs 3.4.11.5, 3.4.11.6, and 3.4.11.7 – "≥ 70°F" will be replaced with "within the limits specified in the PTLR."

- SR 3.4.11.8 - "≤ 100°F" will be replaced with "within the limits specified in the PTLR."

- SR 3.4.11.9 - "≤ 50°F" will be replaced with "within the limits specified in the PTLR."

- Figure 3.4.11, "Minimum Reactor Vessel Metal Temperature vs. Reactor Vessel Pressure," will be deleted. A note will be added to page 3.4-30 stating "Next page is 3.4-36." This change is administrative in nature and allows the current TS page numbering to remain the same.

In the EPU LAR (Reference 1), the licensee's proposed changes also included the administrative requirements for a PTLR which will be incorporated as new TS 5.6.6. Accordingly, new TS 5.5.6 would state:

5.6.6 Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)

a. RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

i) Limiting Conditions for Operation Section 3.4.11, "RCS Pressure and Temperature (P/T) Limits"

ii) Surveillance Requirements Section 3.4.11, "RCS Pressure and Temperature (P/T) Limits"

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document:

i) NEDC-33178P-A, "GE Hitachi Nuclear Energy Methodology for Development of Reactor Pressure Vessel Pressure Temperature Curves" Revision 1, June 2009

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

The proposed PTLR adopts the methodology described in NRC-approved NEDC-33178P-A for preparation of the P/T curves. The GGNS PTLR was developed based on the methodology and template provided in NEDC-33178P-A, Revision 1. NRC GL 96-03 allows plants to relocate their P/T curves and numerical values of other P/T limits (such as heatup/cooldown rate) from the plant TSs to a PTLR, which is a licensee-controlled document. The creation of a new definition for the PTLR and the new TS 5.6.6, that adds the administrative reporting requirement TS for the PTLR, are required to support this proposed change. As such, these requirements for relocating the P/T curves are satisfied by the use of an NRC-approved analysis methodology and the incorporation of a reference to this methodology in the proposed administrative TS 5.6.6.

The NRC staff has reviewed the licensee's evaluation of the effects of the EPU on the USE, P/T limits, and RPV and circumferential weld properties in Section 2.1.2 of the SE. The NRC staff has concluded that licensee has adequately addressed the impact of the EPU on the above and the proposed TS changes are acceptable. In addition, the NRC staff has reviewed the licensee's proposed implementation of TSTF- 419-A in Section 2.1.8 of the SE and concludes the proposed PTLR meets the GL 96-03 requirements for the implementation of the TSTF.

3.2.9 New TS 3.7.7, "Main Turbine Bypass System"

The licensee's EPU analyses of events that cause a slow pressurization have been performed crediting the main turbine bypass system. The Main Turbine Bypass System is needed to prevent pressurization during slow pressurization events and, therefore, in the EPU LAR (Reference 1), the licensee proposed adding new TS 3.7.7, "Main Turbine Bypass System." New LCO 3.7.7 would state:

LCO 3.7.7 a. The Main Turbine Bypass System shall be OPERABLE with two Main Turbine Bypass Valves.

<u>OR</u>

b. The following limits are made applicable:

1. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

<u>AND</u>

2. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

APPLICABILITY: THERMAL POWER $\geq$ 70% RTP

New TS 3.7.7 Conditions, Required Actions, and Completion Times would state:

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met or Main Turbine Bypass System is inoperable	A.1 Satisfy the Requirements of the LCO or restore the Main Turbine Bypass System to OPERABLE status.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to <70% RTP.	4 hours

New TS 3.7.7 would include two Surveillance Requirements (SRs), which would state:

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	Verify one complete cycle of each main turbine bypass valve.	31 days
SR 3.7.7.2	Perform a system functional test.	18 months

Two main turbine bypass valves will limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause slow pressurization, such that the Safety Limit MCPR is not exceeded. The proposed change adds a requirement for two of the three main turbine bypass valves to be operable (see PUSAR Section 2.5.4.3). With two or more valves inoperable, adjustments to the LHGR limits (LCO 3.2.1) and the MCPR limits (LCO 3.2.2) may be applied to allow continued operation. The LHGR and MCPR limits for two inoperable main turbine bypass valves will be specified in the COLR. Only two of the three main turbine bypass valves are credited for slow non-limiting anticipated operational occurrences (AOOs) (i.e., those events that cause slow pressurization) such as: the Rod Withdrawal Error (RWE) at power event and the Loss of Feedwater (LOFW) heating event. For the RWE and LOFW events, the licensee has stated that the main turbine bypass valves are needed to prevent pressurization only when these events are initiated from near RTP. As such the licensee has proposed the applicability of the new TS to be greater than or equal to 70% RTP.

The NRC staff has reviewed the Main Turbine Bypass System in Section 2.5.4.3 of the SE. The NRC staff has concluded that the capability to handle steam bypass from the turbine remains unchanged for EPU conditions. For GGNS, the limiting MCPR event will remain the Generator Load Rejection with Bypass Failure (LRNBP) assuming the operability of the Main Turbine Bypass valves during slow transient events. Limiting events at GGNS have been evaluated with no credit for bypass operation.

The main turbine bypass system is included in the BWR/6 Standard Technical Specifications. The license's proposed main turbine bypass system TS is very similar except for the applicability (greater than or equal to 70 percent versus 25 percent in the ISTS) and a SR for response time testing. The licensee has stated that the proposed TS is only needed to support the analysis for slow pressurization events i.e., the RWE and LOFW events, in which the two main turbine bypass valves will be credited. For slow pressurization events, when power is below 70 percent, the turbine control valves have sufficient capacity to maintain reactor pressure within acceptable limits. Therefore, the NRC concludes the applicability can be limited to greater than or equal to 70 percent. The main turbine bypass valves are considered operable when they are capable of opening during a slow pressurization event in response to increasing main steam line pressure. Because slow pressurization events do not credit the response time of the main turbine bypass system, the ISTS SR and definition for Turbine Bypass System Response Time are not included in the GGNS TSs. The SR requirements assure that the Main Turbine Bypass system can open during a slow pressurization event by cycling each valve once every 31 days and performing a system functional test once every 18 months. Based on the above, the NRC staff has concluded that the proposed TS for the Main Turbine Bypass System is acceptable and meets the intent of the ISTS. In addition, the proposed TS is conservative as it provides an additional limitation to the TSs.

3.2.10 Suppression Pool Average Temperature

In Section 2.1, item 7 of Attachment 1 to Reference 1, the licensee proposed not to re-scale the percent reactor thermal power (%RTP) in TS 3.6.2.1, "Suppression Pool Average Temperature" which references 1% RTP. The licensee justified this by stating that the heat input into the suppression pool at 1% RTP under EPU conditions is approximately equal to the normal system heat losses.

The NRC staff agrees with the licensee that the difference between the CLB and the EPU heat inputs into the suppression at 1% RTP would be insignificant and, therefore, the licensee's proposal not to re-scale 1% RTP is acceptable.

3.2.11 New P_a Calculated Peak Containment Pressure (TS 5.5.12)

By letter dated September 9, 2011 (Reference 28), the licensee proposed to add the following sentence to TS 5.5.12:

> The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is 14.8 psig.

During the EPU review the NRC staff identified that the licensee was not using the maximum calculated peak containment pressure for its Appendix J test. The licensee noted it had taken an exception to Appendix J criteria for using the maximum containment based on the small area where the pressure peak occurred, the short time duration of the pressure peak, and the timing of the pressure peak (early in the accident so there is limited source term). The NRC staff noted Appendix J does not allow for deviation from the criteria in Appendix J except by exemption. While the NRC staff agreed the licensee bases appeared reasonable, the use of an alternative pressure required an exemption. The licensee agreed to perform the Appendix J test at the calculated peak containment pressure and specify that the calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is 14.8 psig. The NRC staff has verified that this is the calculated peak containment pressure is 14.8 psig and therefore, the proposed TS change is acceptable. In addition, this change is conservative as the Appendix J test will be performed at a higher pressure which will result in greater leakage but while still requiring the same acceptance criteria. The licensee has informed the NRC staff that the use of the new P_a will be implemented during the current spring 2012 refueling outage prior to the EPU approval.

3.2.12 New SR 3.2.2.2, Scram Time Response

As discussed in Section 3.2.1, TS 3.2.2, MCPR Applicability, Action B.1, and SR 3.2.2.1 Frequency include requirements associated with a thermal power limit of 25%. The NRC staff will approve the proposed change to revise the % RTP to 21.8% RTP. The revision to the % RTP is based on the fuel thermal monitoring threshold (refer to PUSAR Section 2.8.2.1.2). In addition to the above, and in order to maintain operating margin in future cycle-specific core design evaluations and address the expected increase in scram times, a new SR 3.2.2.2 is being added to allow the determination of the operating limit MCPR based on the scram time testing results (i.e., Option B) as discussed in Section 2.8.4.1, "Scram Time Response."

The new SR will require determination of the MCPR limits:

- Once within 72 hours after each completion of SR 3.1.4.1, which provides verification that each control rod scram time is within specified TS limits; and
- Once within 72 hours after each completion of SR 3.1.4.2, which provides verification that a representative sample of each tested control rod scram time is within the defined TS limits; and
- Once within 72 hours after each completion of SR 3.1.4.4, which provides verification of the control rod scram time after work has been performed on the control rod or control rod drive that could affect the scram time.

In the Reference 1, the licensee stated, in part, that that:

> Currently GGNS utilizes the Option A MCPR operating limits. Use of the Option A methodology limits the severity of the operating limits for pressurization events such that non-pressurization events become limiting. As a method to recognize the significant margin typically observed in scram time testing and to improve operating limits, plants have credited the application of a mean scram speed based operating limit (Option B). The Option B basis does not require any additional scram speed data beyond what is required by TS 3.1.4, "Control Rod Scram Times," since the mean scram speed is based on the measured scram speed.
>
> Since transient analyses may take credit for conservatism in the control rod scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analyses. The proposed SR determines the actual scram speed distribution and compares it with the assumed distribution. The MCPR operating limit is then determined based either on the applicable limit associated with TS 3.1.4 or the realistic scram times. This determination must be performed and any necessary changes must be implemented within 72 hours after each set of control rod scram time tests required by SRs 3.1.4.1, 3.1.4.2, and 3.1.4.4 because the effective scram speed distribution may change during the cycle or after maintenance that could affect scram times. The 72 hour Completion Time is acceptable due to the relatively minor changes in the actual control rod scram speed distribution expected during the fuel cycle.
>
> The function of the MCPR operating limit is to ensure that no fuel damage occurs during anticipated operational occurrences. This function is met using either Option A or Option B to determine the MCPR operating limit.
>
> Use of the Option B analysis allows credit for actual faster scram speeds to provide for a lower MCPR operating limit. This lower operating limit ensures that

the MCPR safety limit is not exceeded while providing for additional operating margin.

Global Nuclear Fuels-Americas LLC's proprietary report NEDE-24011P-A, "General Electric Standard Application for Reactor Fuel (GESTAR II)," includes both Option A and Option B limits methodologies and allows the licensee to decide which methodology to use. The licensee had been previously using Option A and now proposes to use Option B which requires new TS 3.2.2.2 (see SE Section 2.8.4.1). As noted above, TS 3.2.2.2 will allow the determination of the operating limit MCPR to be based on the plant-specific scram time testing results. As this topical report has been previously reviewed and approved by the NRC staff and is referenced in the GGNS Core Operating Limits Report (TS 5.6.5, "Core Operating Limits Report (COLR") as an acceptable methodology for determining core operating limits for reload cycle analyses, the NRC staff concludes that this proposed TS change is acceptable. In addition, the MCPR operating limits associated with Options A and B will be included in the COLR.

4.0 REGULATORY COMMITMENTS

By letters dated September 8, 2010 (Reference 1), September 9, 2011 (Reference 28), October 10, 2011 (Reference 33), November 14, 2011 (Reference 35), November 25, 2011 (Reference 36), December 19, 2011 (Reference 38), February 6, 2012 (Reference 39), February 15, 2012 (Reference 40), and June 12, 2012, Entergy made the following regulatory commitments:

1. The Operating License (OL) and Technical Specifications (TSs) Markups submitted as part of the Extended Power Uprate (EPU) will be revised, if required, to be consistent with the NRC approved Power Range Neutron Monitoring System (PRNMS) TSs. (Attachment 1)

2. The Linear Heat Generation Rate (LHGR) and Minimum Critical Power Ratio (MCPR) limits for two inoperable main turbine bypass valves will be specified in the COLR. (Attachment 1)

3. EPU startup testing would be performed as described in Attachment 9, "Extended Power Uprate Startup Test Plan," with the exception of EPU Test 10 - IRM performance.

4. Vibration analysis and testing will be performed as described in Attachment 10 of Reference 1, "Vibration Analysis and Testing Program."

5. Deleted.

6. Approximately 216 MVAR of additional reactive power capability will be distributed appropriately at designated load centers throughout the system to ensure system reliability. (Attachment 12)

7. The GGNS Containment Leakage Rate Program will be updated to incorporate the EPU P_a value. (PUSAR Section 2.2.4.1)

8. The 480 VAC motor control center (MCC) minimum voltages supplied from off-site power are only marginally affected by EPU (0.51 VAC maximum voltage drop). This 0.11% voltage drop has a negligible effect on valve torque and will be incorporated into the affected MOV calculations. (PUSAR Section 2.2.4.2)

9. Relief valves required by the modification to increase the fuel pool cooling and cleanup system heat removal capability will be added to the inservice testing program scope. (PUSAR Section 2.2.4.2)

10. EQ file updates will be completed as required by 10 CFR 50.49 prior to EPU implementation. Remaining life determinations will be made for all Group II items and any required modifications or replacement of equipment will also be completed prior to EPU implementation. (PUSAR Section 2.3.1)

11. The changes to the GGNS EQ program brought about by the implementation of EPU will be documented and administered per Entergy Administrative Procedure, "Environmental Qualification (NUREG-0588 / 10 CFR 50.49)" 01-S-06-57, Revision 0. (PUSAR Section 2.3.1)

12. The existing protective relay settings for the main generator will have to be recalculated due to the increased EPU power output. (PUSAR Section 2.3.2.2)

13. Because the high pressure turbine will be modified to support achieving the EPU RTP level, new allowable values (AVs) (both upper bound and lower bound) in units of psig must be established. The AVs (in psig) will be revised prior to EPU implementation. (PUSAR Section 2.4.1.3.4)

14. The RWL HPSP analytical limit (in psig) will be revised prior to EPU implementation. The RCIS RWL setpoint (in psig) will be validated during power uprate plant ascension start-up testing to ensure the actual plant interlock is cleared consistent with the safety analysis.(PUSAR Section 2.4.1.3.5)

15. Instrumentation and controls listed in PUSAR Table 2.4-2 will be recalibrated and rescaled as required to support EPU.

16. High pressure turbine operating restrictions will be implemented by GGNS to assure operation at speeds other than at speeds within the natural frequency ranges. (PUSAR Section 2.5.1.2.2)

17. Fuel rod thermal-mechanical performance will be evaluated as part of the reload analysis performed for the cycle-specific core. Documentation of acceptable fuel rod thermal-mechanical response will be included in the Supplemental Reload Licensing Report (SRLR) or Core Operating Limits

Report (COLR) consistent with Limitation and Condition 9.10 of NEDC-33173P-A. (PUSAR Section 2.8.5.2.1)

18. GGNS procedures, including system operating, abnormal, and emergency operating procedures, will be revised prior to implementing EPU. (PUSAR Section 2.11.1).

19. As determined by the training analysis process, appropriate classroom, simulator and in-plant training will be conducted prior to power escalation or as required to operate modified systems for plant start up. The simulator will be modified to maintain the required fidelity in accordance with site procedures and ANSI/ANS 3.5 - 1998 (Reference 89). The simulator changes include hardware changes for new and modified instrumentation and controls, software updates for modeling EPU changes and re-tuning of the core physics model for cycle-specific data. Simulator performance will be validated using design analysis data and startup and test data from the EPU project and implementation program. (PUSAR Section 2.11.1.5)

20. When EPU conditions are obtained and data collected at EPU conditions, a final stress analysis will be performed and submitted to the NRC. (Attachment 11)

21. During the subsequent refueling outages the replacement steam dryer will be inspected as recommended in General Electric Service Information Letter (SIL) 644, "BWR Steam Dryer Integrity," dated August 30, 2006. (Attachment 11, Appendix F)

22. Deleted.

23. GGNS will perform periodic surveillances of the Boraflex neutron absorbing material at least every five years using Boron-10 Areal Density Gage for Evaluating Racks (BADGER) testing. The first test campaign will be completed by December 31, 2012.

    The tests will consist of at least 30 panels. The BADGER to RACKLIFE uncertainty will be developed from the test results. This value will be considered acceptable if it is less than the existing BADGER/ RACKLIFE uncertainty. Additionally, the minimum BADGER areal density results will be confirmed to be greater than the CSA assumption. The gap size and location probability distributions will also be compared to those used in the CSA. The acceptability of these parameters will be based on verifying that all of the CSA distributions bound the corresponding BADGER measured distributions. Alternatively, the measured gap distributions are acceptable if the CSA calculations are repeated using the measured gap distributions and the resulting 95/95 k-effective is bounded by the corresponding CSA Region 1 result (see Table 1 of NEDC 33621P, Grand Gulf Nuclear Station Fuel Storage Criticality Safety Analysis of

Spent and New Fuel Storage Racks, Attachment 2 to the November 23, 2010 letter).

RACKLIFE analysis will continue to be performed each cycle. This analysis will include a comparison of the RACKLIFE predicted silica to the plant measured silica. This comparison will determine if adjustments to the RACKLIFE loss coefficient are merited. The analysis will include projections to the next planned RACKLIFE analysis date to ensure current Region I storage locations will not need to be reclassified as Region II storage locations in the analysis interval.

24. During power ascension to EPU conditions, the acoustic pressure within the main steam lines will be monitored, the trending updated, and the resulting pressure loads on the dryer will be compared to the power ascension limit curves, which were determined from the FIV analysis results.

25. Four safety relief valve (SRV) locations on each of the four main steam lines will be used for piping and SRV monitoring. Each location will have three orthogonal accelerometers

26. Upon final selection of the FIV data acquisition system (DAS) and instruments, instrument bias and uncertainty will be addressed by appropriate adjustment of the acceptance limits.

27. In the event GGNS observes excessive vibration during the power ascension, the steam dryer and FIV monitoring limits will ensure that the EPU power ascension is stopped at a level where the valve and dryer loads are acceptable. If this occurs, GGNS will perform a detailed assessment of the FIV loads and piping and SRV responses and provide the NRC with an updated plan to mitigate the excessive vibration or the resulting stresses.

    At GGNS, the initial onset of second shear layer resonance was observed at 203 and 208 Hz. If excessive valve vibration should occur at EPU conditions, the following actions will be pursued: If the MSL strain gage data indicates that acoustic loads are of low to medium amplitude, the sensitive piping and valve modal response would be identified using the accelerometer data and piping/SRV models and piping/SRV support modifications would be identified to shift or eliminate the piping/SRV response mode.

    If the MSL strain gage data indicates that acoustic loads are of high amplitude, indicative of a second shear wave being the primary cause of the excessive vibration, the acoustic data will be used to define the acoustic mode shape in the RPV/piping/SRV system. Then GGNS would:

- mitigate the acoustic loads by employing an acoustic load mitigation device upstream of the SRV branch connections with contributing acoustic sources or

- modify the SRV-piping geometry to mitigate the acoustic response.

28. Group III non-qualified electrical splices for the six components will be replaced with qualified splices prior to EPU implementation.

29. Responses to items 2, 5, 6, and 9 will be provided by 11/17/2011.

30. Response to remaining RAI 2 will be provided.

31. The final machined pad for each tie bar will be confirmed to be of sufficient thickness to ensure the stresses in the pad remain within the final stress results.

32. Entergy will provide data for the following simulator scenario runs on or before February 15, 2012:

    1. Worst-case ATWS long-term scenario at EPU conditions. Include plots, sequence of events, and initial conditions.

    2. Worst-case ATWS short-term pressure peak scenario at EPU conditions. Include plots, sequence of events, and initial conditions.

33. Responses to items 1, 4 and 8 through 13 will be provided.

34. Entergy will include the remaining qualified partial penetration welds in these areas as well as the full-depth groove welds that replaced those partial penetration welds that could not be qualified in its' inspection plan. These welds are to be inspected during the baseline inspection to be performed at the end of the cycle following the power uprate outage. (response to RAI 5)

35. Entergy made the commitment to provide a summary report describing the conclusions of the SSES Unit 2 skirt crack evaluation as well as the potential impact of its findings on the GGNS steam dryer once the root cause evaluation effort has been finalized in Reference 3. This information is to be provided in response to RAI 12 by 2/15/2012. (response to RAI 5)

36. The responses to RAIs 8, 10 and 12 will be provided.

37. The bounding stress projections using wide band and narrow band methods will be validated for GGNS using on-dryer pressure, acceleration

and strain instrumentation as described in our response to RAI-9 (EMCB Steam Dryer Round 5). (Response to RAI-01)

38. During power ascension to EPU, Entergy will assess dryer vibration performance in accordance with the response to RAI-13.

39. Instrument calibration and power ascension testing will be performed in accordance with the response to RAI 09.

40. Entergy will include the requested information with the summary report of data from the main steam line strain gages and on-dryer instrumentation as stipulated in proposed Operating License Condition 2.C.(46)(a)3. GGNS shall not increase power above 3898 MWt until the NRC Project Manager notifies GGNS the NRC accepts the requested information or NRC questions regarding the information have been addressed. If no questions are identified within 240 hours after the NRC receives the information, power ascension may continue.

The licensee stated that regulatory commitments 1, 29, 30, 31, 32, 33, 35, and 36 have been implemented.

The NRC staff concludes that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitments are best provided by the licensee's administrative processes, including its commitment management program. The above regulatory commitments do not warrant the creation of regulatory requirements (items requiring prior NRC approval of subsequent changes).

5.0 RECOMMENDED AREAS FOR INSPECTION

As described above, the NRC staff conducted an extensive review of the licensee's plans and analyses related to the proposed EPU and concluded that they are acceptable. The NRC staff's review identified the following areas for consideration by the NRC inspection staff during the licensee's implementation of the proposed EPU:

- Spent Fuel Criticality Analysis
- LTS and ATWS
- Power ascension testing activities (SE Section 2.2.6.6)

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 approval of the EPU LAR.

6.0 STATE CONSULTATION

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

7.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, 51.33, and 51.35, a draft Environmental Assessment and finding of no significant impact was prepared and published in the *Federal Register* on May 11, 2011 (77 FR 27804). The draft Environmental Assessment provided a 30-day opportunity for public comment. No comments were received on the draft Environmental Assessment. The final Environmental Assessment was published in the *Federal Register* on July 16, 2012 (77 FR 41814). 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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

Attachments:
1. List of References
2. List of Acronyms

Principal Contributors: J. Billerbeck, S. Basturescu, A. Rossnyev, T. Mossman, W. Jessup, C. Basavaraju, D. Alley, D. Widrevitz, D. Duvigneaud, N. Iqbal, G. Lapinsky, C. Clemmons, P. Jigar, O. Hopkins, A. Sallman, M. Razzaque

Date: July 18, 2012

ATTACHMENT 1 - REFERENCES

1. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "License Amendment Request, Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated September 8, 2010 (GNRO-2010/00056) (ADAMS Accession No. ML102660409).

2. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Supplemental License Amendment Request, Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated November 18, 2010 (GNRO-2010/00071) (ADAMS Accession No. ML103260003).

3. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Supplemental License Amendment Request, Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated November 23, 2010 (GNRO-2010/00073) (ADAMS Accession No. ML103330146).

4. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated February 23, 2011 (GNRO-2011/00007) (ADAMS Accession No. ML110540534).

5. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated February 23, 2011 (GNRO-2011/00012) (ADAMS Accession No. ML110540540).

6. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated February 23, 2011 (GNRO-2011/00011) (ADAMS Accession No. ML110540545).

7. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated February 23, 2011 (GNRO-2011/00013) (ADAMS Accession No. ML110550318).

8. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated March 9, 2011 (GNRO-2011/00017) (ADAMS Accession No. ML110680507).

9. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated March 9, 2011 (GNRO-2011/00016) (ADAMS Accession No. ML110730025).

10. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated March 22, 2011 (GNRO-2011/00019) (ADAMS Accession No. ML110820262).

11. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated March 30, 2011 (GNRO-2011/00018) (ADAMS Accession No. ML110900275).

12. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated March 31, 2011 (GNRO-2011/00021) (ADAMS Accession No. ML110900586).

13. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated April 14, 2011 (GNRO-2011/00024) (ADAMS Accession No. ML111050134).

14. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated April 21, 2011 (GNRO-2011/00025) (ADAMS Accession No. ML111120329).

15. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated May 3, 2011 (GNRO-2011/00034) (ADAMS Accession No. ML111240288).

16. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated May 5, 2011 (GNRO-2011/00035) (ADAMS Accession No. ML111250552).

17. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated May 11, 2011 (GNRO-2011/00037) (ADAMS Accession No. ML111320263).

18. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated June 8, 2011 (GNRO-2011/00043) (ADAMS Accession No. ML111590836).

19. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated June 15, 2011 (GNRO-2011/00046) (ADAMS Accession No. ML111670059).

20. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated June 21, 2011 (GNRO-2011/00050) (ADAMS Accession No. ML111730235).

21. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated June 23, 2011 (GNRO-2011/00052) (ADAMS Accession No. ML111750244).

22. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated July 6, 2011 (GNRO-2011/00053) (ADAMS Accession No. ML111880138).

23. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated July 28, 2011 (GNRO-2011/00055) (ADAMS Accession No. ML112101485).

24. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated August 25, 2011 (GNRO-2011/00070) (ADAMS Accession No. ML112370770).

25. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated August 29, 2011 (GNRO-2011/00073) (ADAMS Accession No. ML112410566).

26. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Supplemental Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated August 30, 2011 (GNRO-2011/00074) (ADAMS Accession No. ML112420169).

27. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Supplemental Information Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated September 2, 2011 (GNRO-2011/00075) (ADAMS Accession No. ML112490050).

28. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Supplemental Information Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated September 9, 2011 (GNRO-2011/00033) (ADAMS Accession No. ML112521284).

29. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated September 12, 2011 (GNRO-2011/00079) (ADAMS Accession No. ML112550495).

30. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated September 15, 2011 (GNRO-2011/00080) (ADAMS Accession No. ML112580223).

31. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated September 26, 2011 (GNRO-2011/00082) (ADAMS Accession No. ML112690143).

32. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated October 10, 2011 (GNRO-2011/00087) (ADAMS Accession No. ML112840155).

33. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated October 10, 2011 (GNRO-2011/00088) (ADAMS Accession No. ML112840171).

34. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Supplemental Information Pertaining to Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated October 24, 2011 (GNRO-2011/00092) (ADAMS Accession No. ML112980113).

35. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated November 14, 2011 (GNRO-2011/00101) (ADAMS Accession No. ML113190403).

36. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated November 25, 2011 (GNRO-2011/00105) (ADAMS Accession No. ML113290137).

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38 . Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated December 19, 2011 (GNRO-2011/00111) (ADAMS Accession No. ML113530656).

39. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated February 6, 2012 (GNRO-2012/00006) (ADAMS Accession No. ML12039A071).

40. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated February 15, 2012 (GNRO-2012/00009) (ADAMS Accession No. ML120470138).

41. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated February 20, 2012 (GNRO-2012/00011) (ADAMS Accession No. ML120540043).

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43. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated March 21, 2012 (GNRO-2012/00018) (ADAMS Accession No. ML120820025).

44. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated April 5, 2012 (GNRO-2012/00023) (ADAMS Accession No. ML12097A055).

45. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Supplemental Information, Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated April 18, 2012 (GNRO-2012/00024) (ADAMS Accession No. ML12109A308).

46. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Response to Request for Additional Information Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated April 18, 2012 (GNRO-2012/00026) (ADAMS Accession No. ML12109A290).

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48. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Supplemental Information – Power Ascension Test Plan, Regarding Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated May 9, 2012 (GNRO-2012/00046) (ADAMS Accession No. ML12131A535).

49. Krupa, M. A., Entergy Operations, Inc., letter to U.S. Nuclear Regulatory Commission, "Regulatory Commitment Pertaining to License Amendment Request for Extended Power Uprate, Grand Gulf Nuclear Station, Unit 1," dated June 12, 2012 (GNRO-2012/00065) (ADAMS Accession No. ML12165A250).

50. Eisenhut, D. G., U.S. Nuclear Regulatory Commission, letter to J. B. Richard, Mississippi Power & Light Company, "Issuance of Facility Operating License NPF-29 – Grand Gulf Nuclear Station, Unit 1," dated November 1, 1984 (ADAMS Accession No. ML021410165).

51. Jaffe, D. H., U.S. Nuclear Regulatory Commission, letter to William A. Eaton, Entergy Operations, Inc., "Grand Gulf Nuclear Station, Issuance of Amendment Re: 1.7% Increase in Licensed Power Level (TAC No. MB3972)," dated October 10, 2002 (ADAMS Accession No. ML022630304).

52. DeYoung, R. C., U.S. Nuclear Regulatory Commission, letter to N. L. Stampley, Mississippi Power & Light Company, regarding issuance of Construction Permits CPPR-118 and CPPR-119 authorizing construction of the Grand Gulf Nuclear Station, Units 1 and 2, dated September 4, 1974 (ADAMS Accession No. ML021410145).

53. Entergy Operations, Inc., "Grand Gulf Nuclear Station, Unit 1, Updated Final Safety Analysis Report" (*not publicly available*).

54. U.S. Nuclear Regulatory Commission, "Office of Nuclear Reactor Regulation, Review Standard for Extended Power Uprates," RS-001, Revision 0, December 2003 (ADAMS Accession No. ML033640024).

55. GE Nuclear Energy, "Licensing Topical Report, Constant Pressure Power Uprate," NEDC-33004P-A, Revision 4, July 2003 (CLTR) (*not publicly available - proprietary*); public version designated as NEDO-33004-A, Revision 4, July 2003 (ADAMS Accession No. ML032170332).

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ATTACHMENT 2 - LIST OF ACRONYMS

Acronym	Definition
AC	alternating current
ADS	automatic depressurization system
AEC	Atomic Energy Commission
ALARA	as low as reasonably achievable
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	anticipated operational occurrence (moderate frequency transient event)
AOP	alternate operating procedure
AOR	analysis of record
AOV	air-operated valve
AP	annulus pressurization
APRM	average power range monitor
ARI	alternate rod insertion
ART	adjusted reference temperature
ARTS	APRM/RBM/Technical Specifications
ASDC	alternate shutdown cooling
ASME	American Society of Mechanical Engineers
AST	alternate source term
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
AV	allowable value
BOC	beginning of cycle
BOP	balance-of-plant
BPWS	banked position withdrawal system
BSP	backup stability protection
BSW	biological shield wall
BTU	British Thermal Unit
B/U	bias errors and uncertainties
BWR	boiling-water reactor
BWROG	BWR Owners Group
BWRVIP	BWR Vessel and Internals Project
CCW	component cooling water
CDF	core damage frequency
CFD	condensate filter demineralizer
CFR	*Code of Federal Regulations*
CFS	condensate and feedwater system
CLTP	current licensed thermal power
CLTR	Constant Pressure Power Uprate Licensing Topical Report
CO	condensation oscillation

Acronym	Definition
COLR	Core Operating Limits Report
CPPU	Constant Pressure Power Uprate
CPR	critical power ratio
CRAVS	control room area ventilation system
CRD	control rod drive
CRDA	control rod drop accident
CREF	control room emergency filtration system
CREVS	control room emergency ventilation system
CSC	containment spray cooling
CST	condensate storage tank
CUF	cumulative usage factors
CWS	circulating water system
CWT	cooling water temperature
DBA	design-basis accident
DBLOCA	design basis loss-of-coolant accident
DC	direct current
DHR	decay heat removal
DIVOM	Delta CPR over initial CPR versus oscillation magnitude
DLO	dual (recirculation) loop operation
DP	differential pressure
EAB	exclusion area boundary
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFDS	equipment and floor drainage system
EFPY	effective full power years
ELLLA	Extended Load Line Limit Analysis
ELTR1	Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate Licensing Topical Report
ELTR2	Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate Licensing Topical Report
EOC	end of cycle
EOI	Entergy Operations, Inc.
EOL	end of license
EOP	emergency operating procedure
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ESBWR	economic simplified boiling water reactor
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
ESFVS	engineered safety feature ventilation system

Acronym	Definition
ETAP	electrical transient analyzer program
FAC	flow accelerated corrosion
FFWTR	final feedwater temperature reduction
FHA	fuel handling accident
FIV	flow-induced vibration
FPC	fuel pool cooling
FPCCS	fuel pool cooling and cleanup system
FPP	fire protection program
FSAR	final safety analysis report
FWCF	feedwater controller failure maximum demand
FWHOOS	feedwater heater out-of-service
FWS	feedwater system
GDC	general design criteria
GE	General Electric Company
GEH	GE-Hitachi Nuclear Energy Americas LLC
GGNS	Grand Gulf Nuclear Station
GL	generic letter
GNF	global nuclear fuel
GRA	growth rate based algorithm
GWMS	gaseous waste management (offgas) system
HCR	human cognitive reliability
HCTL	heat capacity temperature limit
HELB	high energy line break
HEP	human error probability
HEPA	high efficiency particulate air
HFCL	high flow control line
HP	high pressure
HPCS	high pressure coolant spray
HPT	high pressure turbine
HRA	human reliability analysis
HVAC	heating ventilating and air conditioning
HWL	high water level
IASCC	irradiation-assisted stress corrosion cracking
ICA	interim corrective action
ICF	increased core flow
ID	inside diameter
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	intergranular stress-corrosion cracking
IORV	inadvertent opening of a relief valve
IPB	isolated phase bus
IPE	individual plant examination

Acronym	Definition
IPEEE	individual plant examination of external events
IRM	intermediate range monitor
ISI	inservice inspection
ISLOCA	interfacing system loss-of-coolant accident
ISP	integrated surveillance program
IST	inservice testing
LAR	license amendment request
LCO	limiting condition for operation
LCS	leakage control system
LER	licensee event report
LERF	large early release frequency
LFWH	loss of feedwater heater
LHGR	linear heat generation rate
LLHS	light load handling system
LOCA	loss-of-coolant accident
LOCV	loss of condenser vacuum
LOFW	loss of feedwater
LOOP	loss of offsite power
LP	low pressure
LPCI	low pressure coolant injection
LPCS	low pressure core spray
LPRM	local power range monitor
LPSP	low power setpoint
LRNBP	generator-load rejection with no steam bypass failure
LTR	licensing topical report
LWMS	liquid waste management system
LWR	light-water reactor
MAAP	modular accident analysis program
MAPLHGR	maximum average planar linear heat generation rate
MBTU	millions of BTUs
MC	main condenser
MCES	main condenser evacuation system
MCPR	minimum critical power ratio
MEDP	maximum expected differential pressure
MELB	moderate energy line break
MELLLA	maximum extended load line limit analysis
MeV	million electron volts
MIP	MCPR importance parameter
Mlb	millions of pounds
MLHGR	maximum linear heat generation rate
MOC	middle of cycle

Acronym	Definition
MOV	motor operated valve
MSIV	main steam isolation valve
MSIVC	main steam isolation valve closure
MSIVF	main steam isolation valve closure with scram on high flux
MSL	main steam line
MSLB	main steam line break
MSLBA	main steam line break accident
MSRV	main steam relief valve
MSS	main steam system
MVA	million volt amps
MVAR	megavolt ampere reactive
Mvar	MegaVARS
MWe	megawatt electric
MWt	megawatt thermal
NCL	natural circulation line
NEI	Nuclear Energy Institute
NPSH	net positive suction head
NPSHR	net positive suction head required
NRC	Nuclear Regulatory Commission
NSSS	nuclear steam supply system
NTSP	nominal trip set point
NUMAC	Nuclear Management and Control
NUMARC	Nuclear Management and Resources Council, Inc.
NUREG	Nuclear Regulatory Commission technical report designation
OLMCPR	operating limit minimum critical power ratio
OLTP	original licensed thermal power
OM Code	operations and maintenance code
OOS	out-of-service
OPRM	oscillation power range monitor
PBDA	period based detection algorithm
PCS	pressure control system
PCT	peak clad temperature
PRA	probabilistic risk assessment
PRFD	pressure regulator failure downscale
PRFO	pressure regulator failure open
PRNMS	Power Range Neutron Monitoring System
PSA	probabilistic safety analysis
psi	pounds per square inch
psia	pounds per square inch - absolute
psid	pounds per square inch - differential
psig	pounds per square inch - gage

Acronym	Definition
PSD	power spectral density
PSP	pressure suppression pressure
P-T	pressure-temperature
PTLR	pressure and temperatures limits report
PUSAR	power uprate safety analysis report
RAI	request for additional information
RBM	rod block monitor
RCIC	reactor core isolation cooling
RCIS	reactor control and information system
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RFO	refueling outage
RG	Regulatory Guide
RHR	residual heat removal
RIPD	reactor internal pressure difference
RLA	reload licensing analysis
RPC	rod pattern controller
RPT	recirculation pump trip
RPV	reactor pressure vessel
RRS	reactor recirculation system
RSLB	recirculation system line break
RT_{NDT}	reference temperature of nil-ductility transition
RTP	rated thermal power
RVI	reactor vessel internals
RWCU	reactor water cleanup system
RWE	rod withdrawal error
RWL	rod withdrawal limiter
RWM	rod worth minimizer
SAFDL	specified acceptable fuel design limits
SAR	safety analysis report
SBO	station blackout
scfh	standard cubic feet per hour
SDC	shutdown cooling
SE/SER	safety evaluation/safety evaluation report
SFP	spent fuel pool
SFPAVS	spent fuel pool area ventilation system
SGTS	standby gas treatment system
SIL	service information letter
SJAE	steam jet air ejectors
SLCS	standby liquid control system
SLMCPR	safety limit minimum critical power ratio

Acronym	Definition
SLO	single loop operation
Sm	code-allowable stress limit
SORV	stuck open SRV
SP	suppression pool
SPC	suppression pool cooling
SPDS	safety parameter display system
SPMU	suppression pool makeup
SRLR	supplemental reload licensing report
SRM	source range monitor
SRP	Standard Review Plan
SRV	safety relief valve(s)
SRVDL	safety relief valve discharge line
SSC	structures, systems, and components
SSE	safe shutdown earthquake
SSW	station service water
STP	simulated thermal power
SWMS	solid waste management systems
SWS	station service water system
TAF	top of active fuel
TAVS	turbine area ventilation system
TBS	turbine bypass system
TEDE	total effective dose equivalent
TFSP	turbine first-stage pressure
TGSS	turbine gland sealing system
TID	total integrated dose
TIP	traversing in-core probe
TLO	two loop operation
TRM	technical requirements manual
TS	technical specifications
TSV	turbine stop valve
TSVC	turbine stop valve closure
TTNBP	turbine trip with no steam bypass failure
UHS	ultimate heat sink
UPS	uninterruptible power supply
USAR	updated safety analysis report
USE	upper shelf energy
ΔP	differential pressure - psi

version of the SE is provided in Enclosure 3. The Notice of Issuance will be included in the Commission's next biweekly *Federal Register* notice.

Sincerely,

/RA/

Alan B. Wang, Project Manager
Plant Licensing Branch IV
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-416

Enclosures:
1. Amendment No. 191 to NPF-29
2. Safety Evaluation (non-proprietary)
3. Safety Evaluation (proprietary)

cc: Listserv w/o enclosure 3

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Letter and Amendment: ML121210023, Redacted Amendment and SE ML121210020
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DATE	4/30/12	4/30/12	5/16/11	9/16/11	9/7/11
OFFICE	NRR/DE/EMCB/BC*	NRR/DE/EMCB/BC*	NRR/DE/EPNB/BC*	NRR/DE/EVIB/BC*	NRR/DE/EVIB/BC*
NAME	MKhanna	MMurphy	TLupold	MMitchell (SSheng for)	MMitchell (JPoehler for)
DATE	10/5/11	4/30/12	9/16/11	4/27/11	5/9/11
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DATE	8/29/11	4/29/11	6/3/11	9/28/11	5/18/11
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NAME	GCasto	RDennig	RDennig	AMendiola	AUlses
DATE	8/24/11	5/12/11	7/7/11	6/30/11	6/30/11
OFFICE	NRR/DSS/STSB/BC	OGC	NRR/LPL4/BC	NRR/DORL/D	NRR/D
NAME	RElliott	LSubin	MMarkley	MEvans (AHowe for)	ELeeds BBoger for
DATE	5/18/12	6/21/12	7/12/12	7/12/12	7/17/12
OFFICE	NRR/LPL4/PM				
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