Attachment 6A

GNRO-2010/00056

GE-Hitachi Affidavit for Withholding Information from Public Disclosure
Safety Analysis Report

GE-Hitachi Nuclear Energy Americas LLC

AFFIDAVIT

I, **Edward D. Schrull,** state as follows:

(1) I am the Vice President, Regulatory Affairs, Services Licensing, GE-Hitachi Nuclear Energy Americas LLC (GEH), and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in GEH proprietary report NEDC-33477P, "Safety Analysis Report for Grand Gulf Nuclear Station Constant Pressure Power Uprate," Revision 0, dated August 2010. GEH proprietary information in NEDC-33477P is identified by a dotted underline inside double square brackets. [[This sentence is an example.{3}]]. Figures and large equation objects containing GEH proprietary information are identified with double square brackets before and after the object. In each case, the superscript notation {3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

(3) In making this application for withholding of proprietary information of which it is the owner or licensee, GEH relies upon the exemption from disclosure set forth in the Freedom of Information Act (FOIA), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), and 2.390(a)(4) for trade secrets (Exemption 4). The material for which exemption from disclosure is here sought also qualify under the narrower definition of trade secret, within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) The information sought to be withheld is considered to be proprietary for the reasons set forth in paragraphs (4)a. and (4)b. Some examples of categories of information that fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by GEH's competitors without license from GEH constitutes a competitive economic advantage over GEH and/or other companies.

b. Information that, if used by a competitor, would reduce their expenditure of resources or improve their competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product.

c. Information that reveals aspects of past, present, or future GEH customer-funded development plans and programs, that may include potential products to GEH.

d. Information that discloses trade secret and/or potentially patentable subject matter for which it may be desirable to obtain patent protection.

(5) To address 10 CFR 2.390(b)(4), the information sought to be withheld is being submitted to the NRC in confidence. The information is of a sort customarily held in confidence by GEH, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GEH, not been disclosed publicly, and not been made available in public sources. All disclosures to third parties, including any required transmittals to the NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary and/or confidentiality agreements that provide for maintaining the information in confidence. The initial designation of this information as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in the following paragraphs (6) and (7).

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, who is the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge, or who is the person most likely to be subject to the terms under which it was licensed to GEH. Access to such documents within GEH is limited to a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist, or other equivalent authority for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GEH are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary and/or confidentiality agreements.

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains detailed results and conclusions regarding supporting evaluations of the safety-significant changes necessary to demonstrate the regulatory acceptability of the Constant Pressure Power Uprate (CPPU) analysis for a GEH Boiling Water Reactor (BWR). The analysis utilized analytical models and methods, including computer codes, which GEH has developed, obtained NRC approval of, and applied to perform evaluations of CPPUs for a GEH BWR. The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GEH asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GEH's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GEH's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GEH. The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial. GEH's competitive advantage will be lost if its competitors are able to use the results of the GEH experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GEH would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GEH of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing and obtaining these very valuable analytical tools.

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Executed on this 20th day of August 2010.

Edward D. Schrull
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Attachment 6B

GNRO-2010/00056

GE-Hitachi Affidavit for Withholding Information from Public Disclosure

Steam Dryer Evaluation

GE-Hitachi Nuclear Energy Americas LLC

AFFIDAVIT

I, **Edward D. Schrull,** state as follows:

(1) I am the Vice President, Regulatory Affairs, Services Licensing, GE-Hitachi Nuclear Energy Americas LLC ("GEH"), and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in GEH proprietary report NEDC-33601P, "Engineering Report Grand Gulf Replacement Steam Dryer Fatigue Stress Analysis Using PBLE Methodology," Revision 0, dated September 2010. GEH proprietary information in NEDC-33601P is identified by a dotted underline inside double square brackets. [[This sentence is an example.{3}]]. Figures, large equation objects, and some tables containing GEH proprietary information are identified with double square brackets before and after the object. In each case, the superscript notation {3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

(3) In making this application for withholding of proprietary information of which it is the owner or licensee, GEH relies upon the exemption from disclosure set forth in the Freedom of Information Act (FOIA), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), and 2.390(a)(4) for trade secrets (Exemption 4). The material for which exemption from disclosure is here sought also qualify under the narrower definition of trade secret, within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) The information sought to be withheld is considered to be proprietary for the reasons set forth in paragraphs (4)a. and (4)b. Some examples of categories of information that fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by GEH's competitors without license from GEH constitutes a competitive economic advantage over GEH and/or other companies.

b. Information that, if used by a competitor, would reduce their expenditure of resources or improve their competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product.

c. Information that reveals aspects of past, present, or future GEH customer-funded development plans and programs, that may include potential products to GEH.

d. Information that discloses trade secret and/or potentially patentable subject matter for which it may be desirable to obtain patent protection.

(5) To address 10 CFR 2.390(b)(4), the information sought to be withheld is being submitted to the NRC in confidence. The information is of a sort customarily held in confidence by GEH, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GEH, not been disclosed publicly, and not been made available in public sources. All disclosures to third parties, including any required transmittals to the NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary and/or confidentiality agreements that provide for maintaining the information in confidence. The initial designation of this information as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in the following paragraphs (6) and (7).

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, who is the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge, or who is the person most likely to be subject to the terms under which it was licensed to GEH. Access to such documents within GEH is limited to a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist, or other equivalent authority for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GEH are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary and/or confidentiality agreements.

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains detailed GEH design information for the load definition and analysis methodology used in the design and analysis of the BWR steam dryers. GEH utilized prior design information and experience from its operating BWRs with significant resource allocation in developing the methodology over several years at a significant investment.

The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GEH asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GEH's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GEH's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GEH. The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial. GEH's competitive advantage will be lost if its competitors are able to use the results of the GEH experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GEH would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GEH of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing and obtaining these very valuable analytical tools.

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Executed on this 7th day of September 2010.

Edward D. Schrull
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Attachment 7

GNRO-2010/00056

Pressure and Temperature Limits Report

Grand Gulf Nuclear Station

Pressure and Temperature Limits Report (PTLR)

up to 35 Effective Full-Power Years (EFPY)

Revision 0

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1.0 Purpose

The purpose of the Grand Gulf Nuclear Station (GGNS) Pressure and Temperature Limits Report (PTLR) is to present operating limits relating to:

1. Reactor Coolant System (RCS) Pressure versus Temperature limits during Heatup, Cooldown and Hydrostatic/Class 1 Leak Testing;
2. RCS Heatup and Cooldown rates;
3. Reactor Pressure Vessel (RPV) to recirculation loop ΔT requirements during Recirculation Pump startups;
4. RPV bottom head coolant temperature to RPV coolant temperature ΔT requirements during Recirculation Pump startups;
5. RPV head flange bolt-up temperature limits.

This report has been prepared in accordance with the requirements of Technical Specification (TS) 5.6.6, "Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)."

2.0 Applicability

This report is applicable to the GGNS RPV for up to 35 Effective Full-Power Years (EFPY).

The following TS is affected by the information contained in this report:

TS 3.4.11 RCS Pressure and Temperature (P/T) Limits

3.0 Methodology

The limits in this report were derived from the NRC-approved methods listed in TS 5.6.6, using the specific revisions listed below:

1. The neutron fluence was calculated per *Licensing Topical Report, General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation*, NEDC-32983P-A, Rev. 2, January 2006 (Reference 6.1).
2. The pressure and temperature limits were calculated per *GE Hitachi Nuclear Energy Methodology for Development of Reactor Pressure Vessel Pressure-Temperature Curves,* NEDC-33178P-A, Rev. 1, June 2009 (Reference 6.2).

This revision of the PTLR incorporates the following changes:

- Initial issuance of the PTLR.
- Application of GEH Topical Report for P-T Curves
- Fluence application for operation at 4,408 MWt

As discussed in Appendix A, GGNS participates in the BWRVIP Integrated Surveillance Program (ISP) and is not a host plant. No surveillance capsules are currently scheduled to be withdrawn and tested from the GGNS RPV. The GGNS surveillance capsules have an ISP status designation of deferred (standby) per Reference 6.4. The adjusted reference temperature (ART) values for 35 EFPY included in Appendix B are developed using the latest ISP published surveillance data available that is representative of the applicable materials in the GGNS RPV beltline (Ref. 6.3). The surveillance data used in the ART calculations is not obtained from actual GGNS RPV test specimens.

Should actual surveillance capsules be withdrawn and tested from the GGNS RPV (e.g., status change to be an ISP host plant under the BWRVIP ISP), compliance with 10 CFR 50, Appendix H requirements on reporting test results and evaluations on the effects to plant operations parameters (e.g., P-T limits, hydrostatic and leak test conditions) will be in accordance with Section 3 of Reference 6.3.

Changes to the curves, limits, or parameters within this PTLR, based upon new irradiation fluence data of the RPV, surveillance capsule data of the RPV, or other plant design assumptions in the Updated Final Safety Analysis Report (UFSAR), can be made pursuant to 10 CFR 50.59, provided the above methodologies are utilized. The revised PTLR shall be submitted to the NRC upon issuance.

4.0 Operating Limits

The pressure-temperature (P-T) curves (See Figure 1) included in this report represent top head pressure versus minimum vessel metal temperature and incorporate the appropriate non-beltline limits and irradiation embrittlement effects in the beltline region.

The operating limits for pressure and temperature are required for three categories of operation:

1) Curve A: Pressure Test (Hydrostatic Pressure Test and Leak Test)

Curve A may be used during pressure tests at times when the coolant temperature heatup or cooldown rate is ≤20°F/hr during a hydrotest and when the core is not critical.

2) Curve B: Non-Nuclear Heatup / Cooldown

Curve B must be used whenever Curve A or Curve C do not apply. In other words, this curve must be followed during times when the coolant heatup or cooldown rate is greater than 20°F/hr during a pressure test and when the core is not critical. Additionally, when performing low-power physics testing, Curve B must be followed. The heatup and cooldown rate is limited to ≤100°F/ hr when using Curve B.

3) Curve C: Core Critical Operation

This curve must be used when the core is critical with the exception as noted in 2) during low-power physics testing activities. The heatup and cooldown rate is limited to ≤100°F/ hr when using Curve C.

Complete P-T curves were developed for 35 EFPY. The P-T curves are provided in Figure1 and a tabulation of the curves is included in Table1.

Other temperature limits applicable to the RPV are:

- RPV bottom head coolant temperature to RPV coolant temperature ΔT limit during Recirculation Pump startup: ≤ 100 °F.
- Recirculation loop coolant temperature in the loop to be started to RPV coolant temperature ΔT limit during Recirculation Pump startup: ≤ 50 °F.
- RPV flange and head flange temperature limit: ≥ 70 °F.

5.0 Discussion

The computer codes described in References 6.1 and 6.2 were used in the development of the P-T curves for GGNS.

The method for determining the initial Reference Temperature of the Nil-Ductility Transition (RT_{NDT}) for all vessel materials is that defined in Section 4.1.2 of Reference 6.2. Initial RT_{NDT} values for all vessel materials considered are presented in tables in Appendix B, “GGNS Reactor Pressure Vessel P-T Curve Supporting Plant-Specific Information.”

For GGNS, the limiting material, plate heat A1224-1, considered Procedure 1 defined in Appendix I of Reference 6.2. This procedure was used because the vessel material and the surveillance material are identical heats.

For GGNS, there are four thickness discontinuities: 1) Bottom Head to Support Skirt; 2) Bottom Head to Shell #1; 3) Shell #1 to Shell Ring #2, and Shell Ring #3 and Shell Ring #4. There is also a thickness discontinuity between the top head dollar plate and torus; this discontinuity is bounded by the top head evaluation. The P-T curves defined in Section 4.3 of Reference 6.2 are based upon an RT_{NDT} of 19°F for Bottom Head Curves A and C, 24.6°F for Bottom Head Curve B, and -16°F for the Upper Vessel for all curves. The 35 EFPY beltline curves are based on an ART of 43°F. Curves based on these temperatures bound the requirements due to the thickness discontinuities.

The ART of the limiting beltline material is used to adjust the beltline P-T curves to account for irradiation effects. Regulatory Guide 1.99, Revision 2 (RG 1.99) provides the methods for determining the ART. The RG 1.99 methods for determining the limiting material and adjusting the P-T curves using ART are discussed in this section.

The vessel beltline copper and nickel values, except for the N12 nozzle, were obtained from the evaluation presented in the Integrated Surveillance Program (Reference 6.3). The N12 nozzle was evaluated using the limiting material properties (chemistry and initial RT_{NDT}) of the adjoining Shell Ring #2. The copper (Cu) and nickel (Ni) values were used to determine chemistry factors (CF) in accordance with RG 1.99 and Reference 6.3 for welds and plates. ART values for 35 EFPY are included in Appendix B.

The P-T curves for the non-beltline region were developed for a Boiling-Water Reactor Product Line 6 (BWR/6) with nominal inside diameter of 251 inches. The analysis is considered appropriate for GGNS, since it is a BWR/6 with a nominal inside diameter is 251 inches. The generic value was adapted to the conditions at GGNS using plant-specific RT_{NDT} values for the reactor pressure vessel.

The peak RPV ID fluence used in the P-T curve evaluation for 35 effective full power years (EFPY) is 2.53E+18 n/cm^2, which was calculated using methods that comply with the guidelines of RG 1.190, (Reference 6.1).

This fluence applies to the lower-intermediate plates and associated longitudinal welds. The fluence is adjusted for the lower plates and associated longitudinal welds and the girth weld based upon a factor of 0.1336; hence, the peak ID surface fluence for these components is 3.38E+17 n/cm^2. Similarly, the fluence is adjusted for the N12 nozzle

based upon a factor of 0.1111; hence the peak ID surface fluence used for this component is 2.81E+17 n/cm^2.

The P-T curves for the heatup and cooldown operating conditions at a given EFPY apply for both the 1/4T and 3/4T locations. When combining pressure and thermal stresses, it is usually necessary to evaluate stresses at the 1/4T location (inside surface flaw) and the 3/4T location (outside surface flaw). This is because the thermal gradient tensile stress of interest is in the inner wall during cooldown and the outer wall during heatup. However, as a conservative simplification, the thermal gradient stress at the 1/4T location is assumed to be tensile for both heatup and cooldown. This results in the approach of applying the maximum tensile stress at the 1/4T location. This approach is conservative because irradiation effects cause the allowable toughness, K_{Ir}, at 1/4T to be less than that at 3/4T for a given metal temperature. This approach causes no operational difficulties, since the BWR is at steam saturation conditions during normal operation, well above the heatup/cooldown temperature curve limits.

For the core not critical curve (Curve B) and the core critical curve (Curve C), the P-T curves specify a coolant heatup and cooldown temperature rate of ≤ 100°F/hr for which the curves are applicable. However, the core not critical and the core critical curves were also developed to bound transients defined on the RPV thermal cycle diagram and the nozzle thermal cycle diagrams. The P/T limits and corresponding heatup/cooldown rates of either Curve A or B may be applied while achieving or recovering from hydrostatic pressure and leak test conditions. Curve A may be used for the hydrostatic pressure and leak test if a coolant heatup and cooldown rate of ≤ 20°F/hr is maintained. Otherwise, the limits of Curve B apply when performing the hydrostatic pressure and leak test. For GGNS, plate heat A1224-1 is the limiting material for the beltline region for 35 EFPY. The initial RT_{NDT} for the A1224-1 plate materials is 0°F. The generic pressure test P-T curve is applied to the GGNS A1224-1 plate curve by shifting the P vs. (T - RT_{NDT}) values to reflect the ART value of 42.6°F (See Appendix B, GGNS Adjusted Reference Temperatures - 35 EFPY). Using the fluence discussed above, 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.

In order to ensure that the limiting vessel discontinuity has been considered in the development of the P-T curves, the methods in Sections 4.3.2.1 and 4.3.2.2 of Ref. 6.2 for the non-beltline and beltline regions, respectively, are applied.

6.0 References

6.1 Licensing Topical Report NEDC-32983P-A, *General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation*, Rev. 2, January 2006. (NRC SER included in the non-proprietary version - ML072480121)

6.2 *Final Safety Evaluation for Boiling Water Reactors Owners Group Licensing Topical Report NEDC-33178P, General Electric Methodology for Development of Reactor Pressure Vessel Pressure- Temperature Curves*, Revision 1, June 2009. (NRC SER included in the ML092370487)

6.3 *BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Data Source Book and Plant Evaluations*, BWRVIP-135, Revision 1, EPRI, Palo Alto, CA, (EPRI Proprietary).

6.4 *BWR Vessel and Internals Project, Updated BWR Integrated Surveillance Program (ISP) Implementation Plan,* BWRVIP-86-A, EPRI, Palo Alto, CA: 2002. 1003346. (EPRI Proprietary).

6.5 *Pressure-Temperature Limits Report, Entergy Operations, Inc.., Grand Gulf Nuclear Station*, 0000-0113-9637-R0, Revision 0, DRF 0000-0113-9625 Class III (GEH Proprietary Information), June 2010 (Task Report T0317).

Figure 1 – Composite P-T Curves Effective for up to 35 EFPY
[Without Uncertainty for Instrumentation Errors]

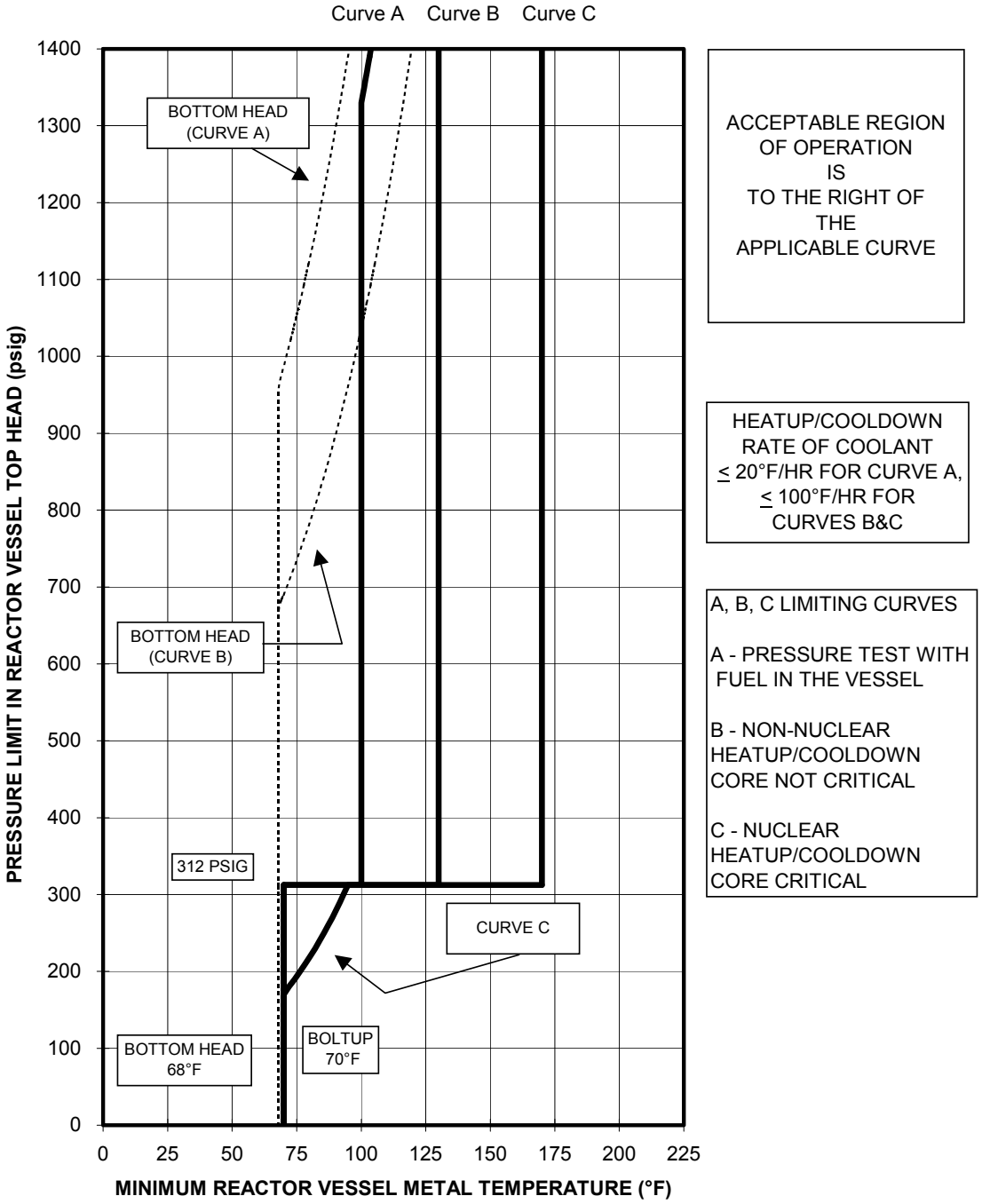


Table 1 – Tabulation of Curves – 35 EFPY

Required Metal Temperature with Required Coolant Heatup / Cooldown Rate at 100°F/hr for Curves B & C and 20 °F/hr for Curve A for Figure 1

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	UPPER VESSEL & BELTLINE AT 35 EFPY CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	UPPER VESSEL BELTLINE AT 35 EFPY CURVE B (°F)	LIMITING 35 EFPY CURVE C (°F)
0	68.0	70.0	68.0	70.0	70.0
10	68.0	70.0	68.0	70.0	70.0
20	68.0	70.0	68.0	70.0	70.0
30	68.0	70.0	68.0	70.0	70.0
40	68.0	70.0	68.0	70.0	70.0
50	68.0	70.0	68.0	70.0	70.0
60	68.0	70.0	68.0	70.0	70.0
70	68.0	70.0	68.0	70.0	70.0
80	68.0	70.0	68.0	70.0	70.0
90	68.0	70.0	68.0	70.0	70.0
100	68.0	70.0	68.0	70.0	70.0
110	68.0	70.0	68.0	70.0	70.0
120	68.0	70.0	68.0	70.0	70.0
130	68.0	70.0	68.0	70.0	70.0
140	68.0	70.0	68.0	70.0	70.0
150	68.0	70.0	68.0	70.0	70.0
160	68.0	70.0	68.0	70.0	70.0
170	68.0	70.0	68.0	70.0	70.0
180	68.0	70.0	68.0	70.0	71.9
190	68.0	70.0	68.0	70.0	74.2
200	68.0	70.0	68.0	70.0	76.3
210	68.0	70.0	68.0	70.0	78.3
220	68.0	70.0	68.0	70.0	80.3
230	68.0	70.0	68.0	70.0	82.1
240	68.0	70.0	68.0	70.0	83.9
250	68.0	70.0	68.0	70.0	85.6
260	68.0	70.0	68.0	70.0	87.2
270	68.0	70.0	68.0	70.0	88.8
280	68.0	70.0	68.0	70.0	90.3
290	68.0	70.0	68.0	70.0	91.8
300	68.0	70.0	68.0	70.0	93.2

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	UPPER VESSEL & BELTLINE AT 35 EFPY CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	UPPER VESSEL BELTLINE AT 35 EFPY CURVE B (°F)	LIMITING 35 EFPY CURVE C (°F)
310	68.0	70.0	68.0	70.0	94.5
312.5	68.0	70.0	68.0	70.0	94.9
312.5	68.0	100.0	68.0	130.0	170.0
320	68.0	100.0	68.0	130.0	170.0
330	68.0	100.0	68.0	130.0	170.0
340	68.0	100.0	68.0	130.0	170.0
350	68.0	100.0	68.0	130.0	170.0
360	68.0	100.0	68.0	130.0	170.0
370	68.0	100.0	68.0	130.0	170.0
380	68.0	100.0	68.0	130.0	170.0
390	68.0	100.0	68.0	130.0	170.0
400	68.0	100.0	68.0	130.0	170.0
410	68.0	100.0	68.0	130.0	170.0
420	68.0	100.0	68.0	130.0	170.0
430	68.0	100.0	68.0	130.0	170.0
440	68.0	100.0	68.0	130.0	170.0
450	68.0	100.0	68.0	130.0	170.0
460	68.0	100.0	68.0	130.0	170.0
470	68.0	100.0	68.0	130.0	170.0
480	68.0	100.0	68.0	130.0	170.0
490	68.0	100.0	68.0	130.0	170.0
500	68.0	100.0	68.0	130.0	170.0
510	68.0	100.0	68.0	130.0	170.0
520	68.0	100.0	68.0	130.0	170.0
530	68.0	100.0	68.0	130.0	170.0
540	68.0	100.0	68.0	130.0	170.0
550	68.0	100.0	68.0	130.0	170.0
560	68.0	100.0	68.0	130.0	170.0
570	68.0	100.0	68.0	130.0	170.0
580	68.0	100.0	68.0	130.0	170.0
590	68.0	100.0	68.0	130.0	170.0
600	68.0	100.0	68.0	130.0	170.0
610	68.0	100.0	68.0	130.0	170.0
620	68.0	100.0	68.0	130.0	170.0
630	68.0	100.0	68.0	130.0	170.0

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	UPPER VESSEL & BELTLINE AT 35 EFPY CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	UPPER VESSEL BELTLINE AT 35 EFPY CURVE B (°F)	LIMITING 35 EFPY CURVE C (°F)
640	68.0	100.0	68.0	130.0	170.0
650	68.0	100.0	68.0	130.0	170.0
660	68.0	100.0	68.0	130.0	170.0
670	68.0	100.0	68.0	130.0	170.0
680	68.0	100.0	68.7	130.0	170.0
690	68.0	100.0	69.9	130.0	170.0
700	68.0	100.0	71.0	130.0	170.0
710	68.0	100.0	72.2	130.0	170.0
720	68.0	100.0	73.3	130.0	170.0
730	68.0	100.0	74.4	130.0	170.0
740	68.0	100.0	75.5	130.0	170.0
750	68.0	100.0	76.6	130.0	170.0
760	68.0	100.0	77.6	130.0	170.0
770	68.0	100.0	78.6	130.0	170.0
780	68.0	100.0	79.6	130.0	170.0
790	68.0	100.0	80.6	130.0	170.0
800	68.0	100.0	81.5	130.0	170.0
810	68.0	100.0	82.5	130.0	170.0
820	68.0	100.0	83.4	130.0	170.0
830	68.0	100.0	84.3	130.0	170.0
840	68.0	100.0	85.2	130.0	170.0
850	68.0	100.0	86.0	130.0	170.0
860	68.0	100.0	86.9	130.0	170.0
870	68.0	100.0	87.7	130.0	170.0
880	68.0	100.0	88.6	130.0	170.0
890	68.0	100.0	89.4	130.0	170.0
900	68.0	100.0	90.2	130.0	170.0
910	68.0	100.0	91.0	130.0	170.0
920	68.0	100.0	91.7	130.0	170.0
930	68.0	100.0	92.5	130.0	170.0
940	68.0	100.0	93.3	130.0	170.0
950	68.0	100.0	94.0	130.0	170.0
960	68.0	100.0	94.7	130.0	170.0
970	68.6	100.0	95.5	130.0	170.0
980	69.4	100.0	96.2	130.0	170.0

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	UPPER VESSEL & BELTLINE AT 35 EFPY CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	UPPER VESSEL BELTLINE AT 35 EFPY CURVE B (°F)	LIMITING 35 EFPY CURVE C (°F)
990	70.2	100.0	96.9	130.0	170.0
1000	71.0	100.0	97.6	130.0	170.0
1010	71.7	100.0	98.2	130.0	170.0
1020	72.5	100.0	98.9	130.0	170.0
1030	73.3	100.0	99.6	130.0	170.0
1035	73.6	100.0	99.9	130.0	170.0
1040	74.0	100.0	100.2	130.0	170.0
1050	74.7	100.0	100.9	130.0	170.0
1055	75.1	100.0	101.2	130.0	170.0
1060	75.4	100.0	101.5	130.0	170.0
1070	76.2	100.0	102.1	130.0	170.0
1080	76.9	100.0	102.8	130.0	170.0
1090	77.6	100.0	103.4	130.0	170.0
1100	78.2	100.0	104.0	130.0	170.0
1105	78.6	100.0	104.3	130.0	170.0
1110	78.9	100.0	104.6	130.0	170.0
1120	79.6	100.0	105.2	130.0	170.0
1130	80.2	100.0	105.8	130.0	170.0
1140	80.9	100.0	106.3	130.0	170.0
1150	81.5	100.0	106.9	130.0	170.0
1160	82.1	100.0	107.5	130.0	170.0
1170	82.8	100.0	108.0	130.0	170.0
1180	83.4	100.0	108.6	130.0	170.0
1190	84.0	100.0	109.1	130.0	170.0
1200	84.6	100.0	109.7	130.0	170.0
1210	85.2	100.0	110.2	130.0	170.0
1220	85.8	100.0	110.8	130.0	170.0
1230	86.3	100.0	111.3	130.0	170.0
1240	86.9	100.0	111.8	130.0	170.0
1250	87.5	100.0	112.3	130.0	170.0
1260	88.0	100.0	112.8	130.0	170.0
1270	88.6	100.0	113.3	130.0	170.0
1280	89.1	100.0	113.8	130.0	170.0
1290	89.7	100.0	114.3	130.0	170.0
1300	90.2	100.0	114.8	130.0	170.0

PRESSURE (PSIG)	BOTTOM HEAD CURVE A (°F)	UPPER VESSEL & BELTLINE AT 35 EFPY CURVE A (°F)	BOTTOM HEAD CURVE B (°F)	UPPER VESSEL BELTLINE AT 35 EFPY CURVE B (°F)	LIMITING 35 EFPY CURVE C (°F)
1310	90.7	100.0	115.3	130.0	170.0
1320	91.3	100.0	115.8	130.0	170.0
1330	91.8	100.0	116.2	130.0	170.0
1340	92.3	100.0	116.7	130.0	170.0
1350	92.8	100.0	117.2	130.0	170.0
1360	93.3	100.4	117.6	130.0	170.0
1370	93.8	100.9	118.1	130.0	170.0
1380	94.3	101.4	118.5	130.0	170.0
1390	94.8	102.0	119.0	130.0	170.0
1400	95.3	102.5	119.4	130.0	170.0

Appendix A

Reactor Vessel Material Surveillance Program

In accordance with 10 CFR 50, Appendix H, Reactor Vessel Material Surveillance Program Requirements, the first surveillance capsule was removed from the GGNS reactor vessel during refueling outage (RFO) 07 and returned to the reactor during RFO-08 without testing.

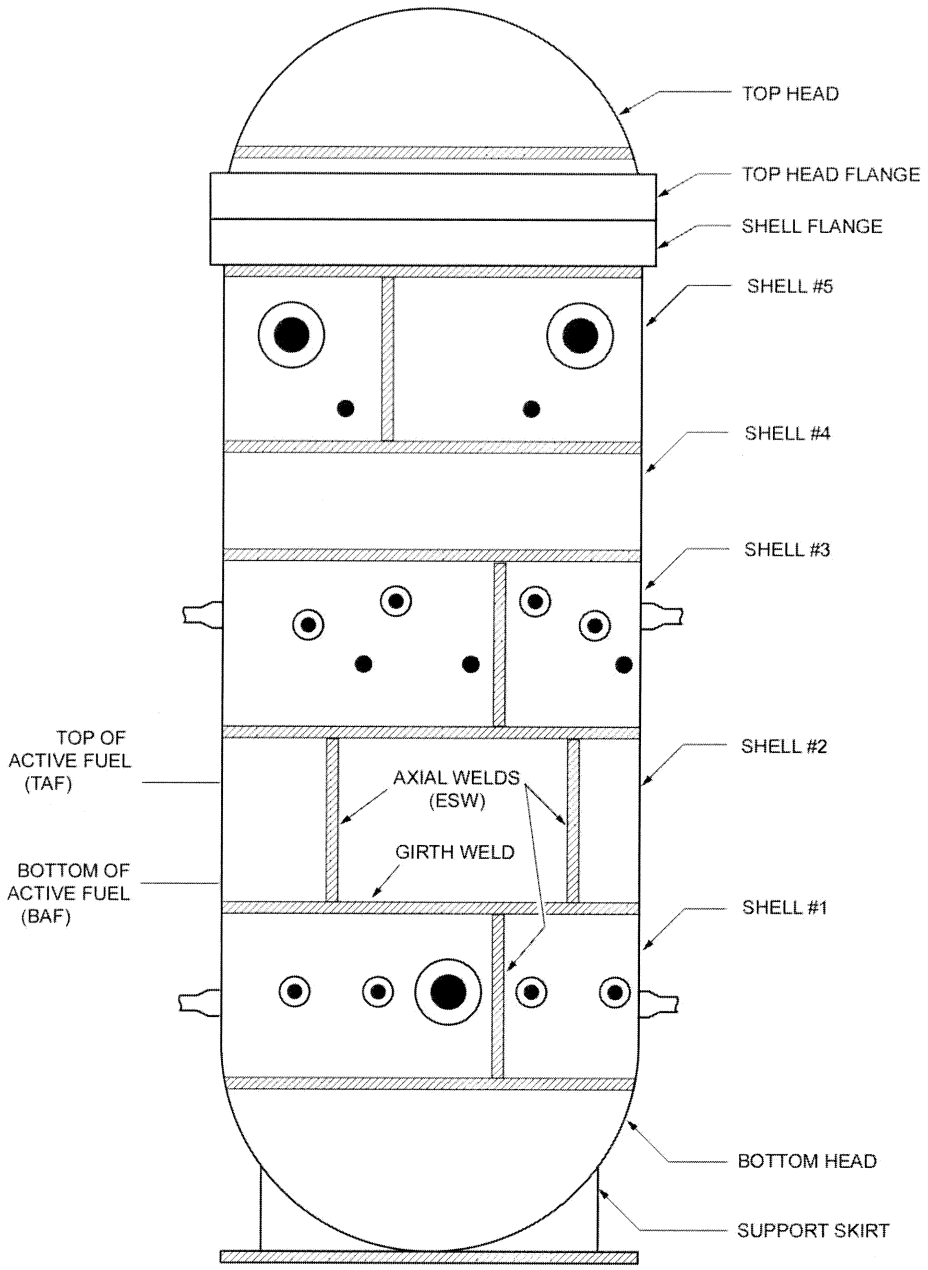
As described in GGNS Updated Final Safety Analysis Report (UFSAR) Section 5.3.1.6, Material Surveillance, the Integrated Surveillance Program will determine the removal schedule for the GGNS surveillance capsules. The Grand Gulf material surveillance program is administered in accordance with the BWR Vessel and Internals Project Integrated Surveillance Program (BWRVIP ISP). The ISP combines the U.S. BWR surveillance programs into a single integrated program. This program uses similar heats of materials in the surveillance programs of BWRs to represent the limiting materials in other vessels. It also adds data from the BWR Supplemental Surveillance Program (SSP). Per the BWRVIP ISP, no capsules are scheduled to be withdrawn from the Grand Gulf vessel. Other plants will remove and test specimens that represent the Grand Gulf vessel.

Appendix B

GGNS Reactor Pressure Vessel P-T Curve

Supporting Plant-Specific Information

Figure of GGNS Reactor Pressure Vessel



GGNS Initial RT_{NDT} Values for RPV Materials
Plate and Flange Materials

Component	Heat	Test Temp (°F)	Charpy Energy (ft-lb)			$(T_{50T}-60)$ (°F)	Drop Weight NDT (°F)	RT_{NDT} (°F)
Top Head & Flange								
Top Head Dollar								
36-2	C2448-3	30	71	51	60	-30	-30	-30
Top Head Torus Plates								
36-1-1 thru 36-1-3	C2944-1	70	52	55	53	10	-20	10
36-1-4 thru 36-1-6	B6727-2	40	52	52	50	-20	-20	-20
Top Head Flange								
32-1	48D1682-1-1	30	85	101	113	-30	-30	-30
Shell Courses & Shell Flange								
Shell Flange								
27-1	48D1141-1-1	30	105	87	81	-30	-30	-30
Upper Shell Plates								
24-1-1	C2815-2	70	53	51	56	10	0	10
24-1-2	C2788-2	70	61	51	50	10	-10	10
24-1-3	C2779-2	70	50	53	57	10	0	10
24-1-4	C2788-1	70	58	52	53	10	-20	10
Upper Intermediate Plates								
23-1-1	C2741-2	50	54	68	66	-10	-10	-10
23-1-2	C2779-1	70	52	50	54	10	-10	10
23-1-3	C2741-1	70	66	54	50	10	-30	10
Lower-Intermediate Plates								
22-1-1	C2593-2	20	52	60	61	-40	-30	-30
22-1-2	C2594-1	50	56	50	62	-10	-10	-10
22-1-3	C2594-2	40	67	50	50	-20	0	0
22-1-4	A1224-1	60	52	74	52	0	-20	0
Lower Shell Plates								
21-1-1	A1113-1	70	62	58	60	10	-20	10
21-1-2	C2557-2	70	64	63	72	10	-30	10
21-1-3	C2506-1	40	50	61	71	-20	-30	-20
Bottom Head								
Bottom Head Dollar								
13-1	C2630-2	60	55	53	51	0	-40	0
Bottom Head Torus Plates								
13-2-L	C2539-2	70	53	51	50	10	-20	10
13-2-R	C2539-2	70	53	51	50	10	-20	10
13-3-L	A1145-2	50	51	60	52	-10	-10	-10
13-3-R	A1145-1	70	53	69	55	10	-10	10

GGNS Initial RT_{NDT} Values for RPV Materials, Continued
Nozzle Materials

Component	Heat	Test Temp (°F)	Charpy Energy (ft-lb)			$(T_{50T}-60)$ (°F)	Drop Weight NDT (°F)	RT_{NDT} (°F)
N1 Recirculation Outlet Nozzle								
49-1-1	Q2QL1W	40	105	104	86	-20	-20	-20
49-1-2	Q2QL1W	40	112	96	96	-20	-20	-20
N2 Recirculation Inlet Nozzle								
52-1-1	Q2QL1W	30	62	90	110	-30	-20	-20
52-1-2	Q2QL1W	40	91	70	93	-20	-20	-20
52-1-3	Q2QL1W	30	96	108	77	-30	-20	-20
52-1-4	Q2QL1W	40	85	89	52	-20	-20	-20
52-1-5	Q2QL1W	40	94	70	81	-20	-20	-20
52-1-6	Q2QL4W	40	77	86	72	-20	-20	-20
52-1-7	Q2QL1W	40	60	50	67	-20	-20	-20
52-1-8	Q2QL4W	40	81	67	62	-20	-20	-20
52-1-9	Q2QL1W	40	78	104	86	-20	-20	-20
52-1-10	Q2QL1W	30	80	78	62	-30	-20	-20
52-1-11	Q2QL1W	40	92	112	103	-20	-20	-20
52-1-12	Q2QL1W	30	80	78	62	-30	-20	-20
N3 Steam Outlet Nozzle								
56-1-1	Q2Q65W	30	118	128	121	-30	-20	-20
56-1-2	Q2Q65W	40	113	80	68	-20	-20	-20
56-1-3	Q2Q65W	40	135	125	115	-20	-20	-20
56-1-4	Q2Q65W	40	118	97	103	-20	-20	-20
N4 Feedwater Nozzle								
59-1-1	Q2Q65W	30	74	98	128	-30	-20	-20
59-1-2	Q2Q65W	30	54	98	104	-30	-20	-20
59-1-3	Q2Q65W	30	112	118	140	-30	-20	-20
59-1-4	Q2Q65W	30	76	86	80	-30	-20	-20
59-1-5	Q2Q65W	30	83	109	98	-30	-20	-20
59-1-6	Q2Q65W	30	110	82	98	-30	-20	-20
N5 Core Spray Nozzle								
63-1-1	Q2QL2W	40	71	76	55	-20	-20	-20
63-1-2	Q2QL2W	30	57	95	90	-30	-20	-20
N6 RHR/LPCI Nozzle								
67-1-1	Q2QL2W	40	63	58	70	-20	-20	-20
67-1-2	Q2QL2W	40	70	60	71	-20	-20	-20
67-1-3	Q2QL2W	40	98	103	103	-20	-20	-20
N7 Top Head Spray Nozzle								
71-1	Q2QL13QT	40	83	70	81	-20	-20	-20
Blind Flange 72-2	C2448-3	30	71	51	60	-30	-30	-30
N8 Top Head Spare Nozzle								
74-1	Q2QL19QT	40	85	56	80	-20	-20	-20
Blind Flange 75-1	C2448-3	30	71	51	60	-30	-30	-30
N9 Jet Pump Instrument Nozzle								
77-1-1	Q2QL1W	40	113	111	108	-20	-20	-20
77-1-2	Q2QL1W	20	82	78	79	-40	-20	-20
N10 CRD HYD Return Nozzle								
80-1	Q2QL4W	30	70	58	73	-30	-20	-20
N11 and N18 Core ΔP Nozzle								
84-1-1 and 84-1-2	SB166							
N12 and N13 Instrument Nozzles								
88-1-1 thru 88-1-8	Stainless Steel							
N14 Instrument Nozzles								
91-1-1 thru 91-1-4	Stainless Steel							
N15 Drain Nozzle								
93-1-1 thru 93-1-2	719282	30	180	209	239	-30	-30	-30
N16 Instrument Vibration Nozzles								
95-1	Q2QL4W	30	68	63	54	-30	-20	-20
Blind Flange 96-2	C2448-3	30	71	51	60	-30	-30	-30
N17 Seal Leak Detector Nozzle								
99-1	SB166							

GGNS Initial RT_{NDT} Values for RPV Materials, Continued
Weld Materials

Component	Heat or Heat / Flux / Lot	Test Temp (°F)	Charpy Energy (ft-lb)			$(T_{50T}-60)$ (°F)	Drop Weight NDT (°F)	RT_{NDT} (°F)
Top Head Welds								
Top Head Torus to Dollar Plate (AH)	640892/J424B27AE	0	55	62	62	-60	-70	-60
	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	401P2871/H430B27AF	10	75	76	107	-50	-70	-50
	412L4711/A423B27AH	0	72	83	95	-60	-90	-60
	07R458/S403B27AG	0	59	61	70	-60	-60	-60
	L83978/J414B27AD	-20	51	52	81	-80	-80	-80
Top Head Flange to Torus (AG)	401P2871/H430B27AF	10	75	76	107	-50	-70	-50
	402P3162/H426B27AE	-10	60	54	68	-70	-70	-70
	412L4711/A423B27AH	0	72	83	95	-60	-90	-60
	07R458/S403B27AG	0	59	61	70	-60	-60	-60
	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	640892/J424B27AE	0	55	62	62	-60	-70	-60
	412P3611/J417B27AF	-20	52	65	69	-80	-80	-80
	401S0371/B504B27AE	-20	61	84	77	-80	-60	-60
Top Head Upper Torus Meridional Welds								
DH, DJ, DK, DM, DN, DP	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
DH, DJ, DN, DP	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
DH, DJ, DK, DM, DN, DP	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
DH, DJ, DK, DM, DN, DP	629865/A421A27AD	-10	69	70	88	-70	-90	-70
DH, DJ, DK, DM, DN, DP	402P3162/H426B27AE	-10	60	54	68	-70	-70	-70
DH	07R458/S403B27AG	0	59	61	70	-60	-60	-60
Cylindrical Shell Circumferential Welds								
Shell Flange to Upper Shell (AE)	5P6756/Linde 124/0342 (Single)	0	55	66	63	-60	-60	-60
	5P6756/Linde 124/0342 (Tandem)	10	64	72	77	-50	-50	-50
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	640892/J424B27AE	0	55	62	62	-60	-70	-60
	07R458/S403B27AG	0	59	61	70	-60	-60	-60
	401P2871/H430B27AF	10	75	76	107	-50	-70	-50
Upper Shell to Upper-Intermediate Shell (AD)	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
	412L4711/A423B27AH	0	72	83	95	-60	-90	-60
	401P2871/H430B27AF	10	75	76	107	-50	-70	-50
	5P6771/Linde 124/0342 (Single)	30	78	53	68	-30	-30	-30
	5P6771/Linde 124/0342 (Tandem)	40	77	81	83	-20	-20	-20
	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	640892/J424B27AE	0	55	62	62	-60	-70	-60
Upper-Intermediate Shell to Lower-Intermediate Shell (AC)	401P2871/H430B27AF	10	75	76	107	-50	-70	-50
	07R458/S403B27AG	0	59	61	70	-60	-60	-60
	412L4711/A423B27AH	0	72	83	95	-60	-90	-60
	5P6771/Linde 124/0342 (Single)	30	78	53	68	-30	-30	-30
	5P6771/Linde 124/0342 (Tandem)	40	77	81	83	-20	-20	-20
Lower-Intermediate Shell to Lower Shell (AB)	4P7216/Linde 124/0156 (Single)	20	51	59	53	-40	-70	-40
	4P7216/Linde 124/0156 (Tandem)	0	64	71	63	-60	-60	-60
Lower Shell to Bottom Head (AA)	5P6214B/Linde 124/0342 (Single)	10	51	56	57	-50	-20	-20
	5P6214B/Linde 124/0342 (Tandem)	40	70	67	62	-20	-20	-20
	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	401S0371/B504B27AE	-20	61	84	77	-80	-60	-60
	401P2871/H430B27AF	10	75	76	107	-50	-70	-50
	412P3611/J417B27AF	-20	52	65	69	-80	-80	-80
	02R486/J404B27AG	-10	52	64	66	-70	-90	-70
	L83978/J414B27AD	-20	51	52	81	-80	-80	-80

GGNS Initial RT_{NDT} Values for RPV Materials, Continued
Weld Materials

Component	Heat or Heat / Flux / Lot	Test Temp (°F)	Charpy Energy (ft-lb)			$(T_{50T}-60)$ (°F)	Drop Weight NDT (°F)	RT_{NDT} (°F)
Cylindrical Shell Vertical Welds								
Welds within Lower Shell Ring								
BA, BB, BC	627260/B322A27AE	30	52	56	51	-30	-40	-30
BA, BB, BC	624063/C228A27A	10	57	59	68	-50	-60	-50
BA , BB, BC	627069/C312A27AG	0	72	64	78	-60	-60	-60
BA	626677/C301A27A	40	53	51	54	-20	-40	-20
BC	624039/D205A27A	-30	64	61	69	-90	-90	-90
BC	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
BC	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
BA , BB, BC	5P6214B/Linde 124/0331 (Single)	10	56	50	54	-50	-50	-50
BA , BB, BC	5P6214B/Linde 124/0331 (Tandem)	10	50	61	64	-50	-40	-40
Welds within Lower-Intermediate Shell Ring								
BD, BE, BF, BG	627260/B322A27AE	30	52	56	51	-30	-40	-30
BD, BE, BF, BG	624063/C228A27A	10	57	59	68	-50	-60	-50
BD, BE, BF, BG	626677/C301A27A	40	53	51	54	-20	-40	-20
BD, BE, BF, BG	627069/C312A27AG	0	72	64	78	-60	-60	-60
BD, BE, BF, BG	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
BD, BE, BF, BG	5P6214B/Linde 124/0331 (Single)	10	56	50	54	-50	-50	-50
BD, BE, BF, BG	5P6214B/Linde 124/0331 (Tandem)	10	50	61	64	-50	-40	-40
Welds within Upper-Intermediate Shell Ring								
BH, BJ, BK	627260/B322A27AE	30	52	56	51	-30	-40	-30
BH, BJ, BK	626677/C301A27A	40	53	51	54	-20	-40	-20
BH, BJ, BK	624063/C228A27A	10	57	59	68	-50	-60	-50
BH, BJ, BK	627069/C312A27AG	0	72	64	78	-60	-60	-60
BH, BJ, BK	5P6214B/Linde 124/0331 (Single)	10	56	50	54	-50	-50	-50
BH, BJ, BK	5P6214B/Linde 124/0331 (Tandem)	10	50	61	64	-50	-40	-40
BJ	624039/D205A27A	-30	64	61	69	-90	-90	-90
Welds within Upper Shell Ring								
BM, BN, BP, BR	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
BM, BN, BP, BR	626677/C301A27A	40	53	51	54	-20	-40	-20
BM, BN, BP, BR	627260/B322A27AE	30	52	56	51	-30	-40	-30
BP	627184/C314A27AH	10	53	66	63	-50	-70	-50
BM, BN, BP, BR	627069/C312A27AG	0	72	64	78	-60	-60	-60
BM, BN, BP, BR	5P6214B/Linde 124/0331 (Single)	10	56	50	54	-50	-50	-50
BM, BN, BP, BR	5P6214B/Linde 124/0331 (Tandem)	10	50	61	64	-50	-40	-40
Bottom Head Welds								
DA	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
DA, DC, DD	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
DC , DD	5P6214B/Linde 124/0331 (Single)	10	56	50	54	-50	-50	-50
DC , DD	5P6214B/Linde 124/0331 (Tandem)	10	50	61	64	-50	-40	-40
DC, DD	627260/B322A27AE	30	52	56	51	-30	-40	-30
DC, DD	626677/C301A27A	40	53	51	54	-20	-40	-20
DC, DD	627069/C312A27AG	0	72	64	78	-60	-60	-60
Support Skirt to Bottom Head	5P5657/Linde 124/0931 (Single)	0	51	55	68	-60	-60	-60
	5P5657/Linde 124/0931 (Tandem)	0	51	57	55	-60	-80	-60
	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	402P3162/H426B27AE	-10	60	54	68	-70	-70	-70
CA, CB, CG	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
CA, CB	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
CA, CB, CG	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
Shroud Support to Vessel Welds								
Shroud Support to Lower Shell	Inconel							
Shroud Support to Bottom Head	Inconel 182							

GGNS Initial RT_{NDT} Values for RPV Materials, Continued
Weld Materials

Component	Heat or Heat / Flux / Lot	Test Temp (°F)	Charpy Energy (ft-lb)			$(T_{50T}-60)$ (°F)	Drop Weight NDT (°F)	RT_{NDT} (°F)
Nozzle Welds								
N1 Recirculation Outlet	05T776/L314A27AH	-10	69	72	81	-70	-70	-70
	627069/C312A27AG	0	72	64	78	-60	-60	-60
	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
	5P5657/Linde 124/0931 (Single)	0	51	55	68	-60	-60	-60
	5P5657/Linde 124/0931 (Tandem)	0	51	57	55	-60	-80	-60
	402P3162/H426B27AE	-10	60	54	68	-70	-70	-70
	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	626677/C301A27A	40	53	51	54	-20	-40	-20
	624063/C228A27A	10	57	59	68	-50	-60	-50
N2 Recirculation Inlet	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
	627260/B322A27AE	30	52	56	51	-30	-40	-30
	626677/C301A27A	40	53	51	54	-20	-40	-20
	627069/C312A27AG	0	72	64	78	-60	-60	-60
	5P5657/Linde 124/0931 (Single)	0	51	55	68	-60	-60	-60
	5P5657/Linde 124/0931 (Tandem)	0	51	57	55	-60	-80	-60
	627184/C314A27AH	10	53	66	63	-50	-70	-50
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
	05T776/L314A27AH	-10	69	72	81	-70	-70	-70
	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	5P6756/Linde 124/0342 (Single)	0	55	66	63	-60	-60	-60
	5P6756/Linde 124/0342 (Tandem)	10	64	72	77	-50	-50	-50
	04T931/A428B27AG	0	65	69	72	-60	-90	-60
	402P3162/H426B27AE	-10	60	54	68	-70	-70	-70
	624063/C228A27A	10	57	59	68	-50	-60	-50
N3 Steam Outlet	401P2871/H430B27AF	10	75	76	107	-50	-70	-50
	402P3162/H426B27AE	-10	60	54	68	-70	-70	-70
	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
	05T776/L314A27AH	-10	69	72	81	-70	-70	-70
	04T931/A428B27AG	0	65	69	72	-60	-90	-60
	07R458/S403B27AG	0	59	61	70	-60	-60	-60
	412L4711/A423B27AH	0	72	83	95	-60	-90	-60
	5P6756/Linde 124/0342 (Single)	0	55	66	63	-60	-60	-60
	5P6756/Linde 124/0342 (Tandem)	10	64	72	77	-50	-50	-50
	3P4955/Linde 124/0342 (Single)	40	51	52	56	-20	-40	-20
	3P4955/Linde 124/0342 (Tandem)	30	60	65	52	-30	-20	-20
	5P6771/Linde 124/0342 (Single)	30	78	53	68	-30	-30	-30
	5P6771/Linde 124/0342 (Tandem)	40	77	81	83	-20	-20	-20
N4 Feedwater Nozzle	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
	626677/C301A27A	40	53	51	54	-20	-40	-20
	627069/C312A27AG	0	72	64	78	-60	-60	-60
	5P5657/Linde 124/0931 (Single)	0	51	55	68	-60	-60	-60
	5P5657/Linde 124/0931 Tandem)	0	51	57	55	-60	-80	-60
	627184/C314A27AH	10	53	66	63	-50	-70	-50
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
	04T931/A428B27AG	0	65	69	72	-60	-90	-60
	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	07R458/S403B27AG	0	59	61	70	-60	-60	-60
	402P3162/H426B27AE	-10	60	54	68	-70	-70	-70
	401P2871/H430B27AF	10	75	76	107	-50	-70	-50

GGNS Initial RT_{NDT} Values for RPV Materials, Continued
Weld Materials

Component	Heat or Heat / Flux / Lot	Test Temp (°F)	Charpy Energy (ft-lb)			(T_{50T}-60) (°F)	Drop Weight NDT (°F)	RT_{NDT} (°F)
N5 Core Spray Nozzles	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
	5P6756/Linde 124/0342 (Single)	0	55	66	63	-60	-60	-60
	5P6756/Linde 124/0342 (Tandem)	10	64	72	77	-50	-50	-50
	05T776/L314A27AH	-10	69	72	81	-70	-70	-70
	627069/C312A27AG	0	72	64	78	-60	-60	-60
N6 LPCI Nozzle	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
	04T931/A428B27AG	0	65	69	72	-60	-90	-60
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
	5P6756/Linde 124/0342 (Single)	0	55	66	63	-60	-60	-60
	5P6756/Linde 124/0342 (Tandem)	10	64	72	77	-50	-50	-50
	05T776/L314A27AH	-10	69	72	81	-70	-70	-70
N7 Top Head Spray Nozzle	401S0371/B504B27AE	-20	61	84	77	-80	-60	-60
	02R486/J404B27AG	-10	52	64	66	-70	-90	-70
	412P3611/J417B27AF	-20	52	65	69	-80	-80	-80
	L83978/J414B27AD	-20	51	52	81	-80	-80	-80
	412L4711/A423B27AH	0	72	83	95	-60	-90	-60
N8 Top Head Spare Nozzle	L83978/J414B27AD	-20	51	52	81	-80	-80	-80
	401S0371/B504B27AE	-20	61	84	77	-80	-60	-60
	412P3611/J417B27AF	-20	52	65	69	-80	-80	-80
	412L4711/A423B27AH	0	72	83	95	-60	-90	-60
	02R486/J404B27AG	-10	52	64	66	-70	-90	-70
N9 Jet Pump Instrumentation Nozzle	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
	04T931/A428B27AG	0	65	69	72	-60	-90	-60
	05T776/L314A27AH	-10	69	72	81	-70	-70	-70
	627260/B322A27AE	30	52	56	51	-30	-40	-30
N10 CRD HYD Return Nozzle	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
	04T931/A428B27AG	0	65	69	72	-60	-90	-60
	05T776/L314A27AH	-10	69	72	81	-70	-70	-70
N11 and N18 Core ΔP Nozzle	Inconel							
N12, N13, N14 Instrument Nozzles								
KA	Inconel 182							
Weld Pad Buildup N13	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
Weld Pad Buildup N13	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
Weld Pad Buildup N12, N13	627184/C314A27AH	10	53	66	63	-50	-70	-50
Weld Pad Buildup N13	05T776/L314A27AH	-10	69	72	81	-70	-70	-70
N15 Drain Nozzle	5P6756 no lot	-20	94	97	105	-80	-60	-60
	626677/C301A27A	40	53	51	54	-20	-40	-20
	627260/B322A27AE	30	52	56	51	-30	-40	-30
	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
N16 Vibration Instrumentation Nozzle	402P3162/H426B27AE	-10	60	54	68	-70	-70	-70
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
	04T931/A428B27AG	0	65	69	72	-60	-90	-60
	05T776/L314A27AH	-10	69	72	81	-70	-70	-70
N17 Seal Leak Detection Nozzle	Inconel							

GGNS Initial RT_{NDT} Values for RPV Materials, Continued
Weld Materials

Component	Heat or Heat / Flux / Lot	Test Temp (°F)	Charpy Energy (ft-lb)			(T_{50T}-60) (°F)	Drop Weight NDT (°F)	RT_{NDT} (°F)
Appurtenance Welds								
Thermocouple Pads								
Shell Flange, Shell Ring #4, Top Head Flange, FW Nozzle	629865/A421A27AD	-10	69	70	88	-70	-90	-70
Bottom Head (Sets 15, 16, 17)	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
Top Head Lifting Lugs	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	L83978/J414B27AD	-20	51	52	81	-80	-80	-80
	401S0371/B504B27AE	-20	61	84	77	-80	-60	-60
	412P3611/J417B27AF	-20	52	65	69	-80	-80	-80
Guide Rod Bracket	Stainless Steel							
Steam Dryer Support Bracket	Stainless Steel							
Steam Dryer Hold Down Brackets to Top Head	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
Core Spray Bracket	Stainless Steel							
Core Spray Pad Buildup	629865/A421A27AD	-10	69	70	88	-70	-90	-70
	627184/C314A27AH	10	53	66	63	-50	-70	-50
	04T931/A428B27AG	0	65	69	72	-60	-90	-60
	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
Refueling Bellows to Shell Flange								
RA	627069/C312A27AG	0	72	64	78	-60	-60	-60
RA	422K8511/G313A27AD	-20	65	74	127	-80	-80	-80
RA	492L4871/A421B27AE	0	50	51	57	-60	-90	-60
RA	492L4871/A421B27AF	10	56	58	61	-50	-80	-50
RH	065900	40	84	80	52	-20	-20	-20
RH	640968/D524M1AF	-20	81	87	98	-80	-40	-40
RH	401S2011/C506M1AG	40	122	111	123	-20	-20	-20
Jet Pump Riser Pads	627184/C314A27AH	10	53	66	63	-50	-70	-50
Feedwater Sparger Bracket	Stainless Steel							
Surveillance Bracket Pads	Stainless Steel							

GGNS Initial RT_{NDT} Values for RPV Materials, Continued
Appurtenance and Bolting Materials

Component	Heat or Heat / Flux / Lot	Test Temp (°F)	Charpy Energy (ft-lb)			$(T_{50T}-60)$ (°F)	Drop Weight NDT (°F)	RT_{NDT} (°F)
Appurtenances								
Support Skirt Forging								
10-1-1	B7128-3	70	53	52	50	10	-50	10
10-1-2	B7128-4	10	58	54	50	-50	-40	-40
Support Skirt Base Plate								
10-2-1 thru 10-2-3	R0588-1	40	113	108	118	-20	-10	-10
10-2-4 thru 10-2-6	R0666-1	70	62	64	62	10	-10	10
Support Skirt Extension								
9-1-1 thru 9-1-2	B7036-2	50	60	55	59	-10	-20	-10
Jet Pump Support								
20-1-1 thru 20-1-4	Inconel							
20-2-1 and 20-5-1	Inconel							
Jet Pump Riser Pads	Stainless Steel							
Shroud Support								
20-4-1 thru 20-4-14	Inconel							
Shroud Support Ring								
20-3-1 thru 20-3-2	Inconel							
Shroud Support Stubs								
17-1-1 thru 17-1-14	Inconel							
Guide Rod Brackets								
106-1-1 thru 106-1-2	Stainless Steel							
Guide Rod Bracket Pads	Stainless Steel							
Steam Dryer Support Brackets								
108-1-1 thru 108-1-6	Stainless Steel							
Steam Dryer Support Bracket Weld	Stainless Steel							
Steam Dryer Hold Down Brackets								
110-1-1 thru 110-1-6	C3072-1A	30	52	61	51	-30	-40	-30
Core Spray Brackets								
116-1-1 thru 116-1-8	Stainless Steel							
Refueling Bellows Skirt								
46-2-1 thru 46-2-3	A2457-9H	100	66	68	69	40	-	40
Extension Bar								
46-1-1 thru 46-1-6	R0503-1	60	57	56	68	0	0	0
Refueling Bellows Bar								
46-1-1 thru 46-1-6	A2457-7	60	50	50	52	0	-20	0
Refueling Bellows Base Plate								
46-3-1 thru 46-3-6	B7891-7A	20	71	67	92	-40	-40	-40
Surveillance Specimen Bracket Pads	Stainless Steel							
Feedwater Sparger Brackets								
112-1-1 thru 112-1-12	Stainless Steel							
Top Head Lifting Lugs								
43-1-1 thru 43-1-4	C2448-3	30	71	51	60	-30	-30	-30

Component	Heat	Test Temp (°F)	Charpy Energy (ft-lb)			Min Lat Exp (mils)	LST (°F)
STUDS							
Closure							
38-1	84025	10	48	50	48	28	10
38-1	84299	10	49	48	53	29	10
N7, N8, N16							
72-4 and 96-4	11312	10	49	50	51	27	10
NUTS							
Closure							
39-5	83706	10	50	51	54	28	10
N7, N8, N16							
72-5	11312	10	49	50	51	27	10
WASHERS							
Closure Washers							
39-6	83706	10	50	51	54	28	10

GGNS Adjusted Reference Temperatures - 35 EFPY

Lower-Intermediate Shell and Axial Welds
Thickness in inches= 6.4375

35 EFPY Peak I.D. fluence = 2.53E+18 n/cm^2
35 EFPY Peak 1/4 T fluence = 1.72E+18 n/cm^2

N12 Nozzles
Thickness in inches= 6.4375

35 EFPY Peak I.D. fluence = 2.81E+17 n/cm^2
35 EFPY Peak 1/4 T fluence = 1.91E+17 n/cm^2

Circumferential Weld AB [8]
Thickness in inches= 6.4375

35 EFPY Peak I.D. fluence = 3.38E+17 n/cm^2
35 EFPY Peak 1/4 T fluence = 2.30E+17 n/cm^2

Lower Shell and Axial Welds [8]
Thickness in inches= 7.0000

35 EFPY Peak I.D. fluence = 3.38E+17 n/cm^2
35 EFPY Peak 1/4 T fluence = 2.22E+17 n/cm^2

COMPONENT	HEAT	%Cu	%Ni	CF	Fitted or Adjusted CF °F	Initial RT_{NDT} °F	1/4 T Fluence n/cm^2	35 EFPY ΔRT_{NDT} °F	σ_I	σ_Δ	Margin °F	35 EFPY Shift °F	35 EFPY ART °F
PLANT-SPECIFIC CHEMISTRIES PLATES:													
	C2593-2	0.04	0.59	26		-30	1.72E+18	13.9	0	6.9	13.9	27.8	-2.2
Shell Ring 2	C2594-1	0.04	0.63	26		-10	1.72E+18	13.9	0	6.9	13.9	27.8	17.8
	C2594-2	0.04	0.63	26		0	1.72E+18	13.9	0	6.9	13.9	27.8	27.8
	A1224-1	0.04	0.65	26		0	1.72E+18	13.9	0	6.9	13.9	27.8	27.8
	A1113-1	0.12 [7]	0.65	84		10	2.22E+17	15.4	0	7.7	15.4	30.7	40.7
Shell Ring 1 [6]	C2557-2	0.12 [7]	0.64	84		10	2.22E+17	15.3	0	7.7	15.3	30.7	40.7
	C2506-1	0.12 [7]	0.66	84		-20	2.22E+17	15.4	0	7.7	15.4	30.8	10.8
AXIAL WELDS [1]:													
Shell Ring 2	5P6214B/0331 Single	0.02	0.82	27		-50	1.72E+18	14.4	0	7.2	14.4	28.8	-21.2
	5P6214B/0331 Tandem	0.02	0.82	27		-40	1.72E+18	14.4	0	7.2	14.4	28.8	-11.2
Shell Ring 1 [6]	5P6214B/0331 Single	0.02	0.82	27		-50	2.22E+17	5.0	0	2.5	5.0	9.9	-40.1
	5P6214B/0331 Tandem	0.02	0.82	27		-40	2.22E+17	5.0	0	2.5	5.0	9.9	-30.1
CIRCUMFERENTIAL WELDS:													
AB [2]	4P7216/0156 Single	0.03	0.79	41		-40	2.30E+17	7.7	0	3.8	7.7	15.4	-24.6
AB [2]	4P7216/0156 Tandem	0.03	0.81	41		-60	2.30E+17	7.7	0	3.8	7.7	15.4	-44.6
NOZZLES:													
N12 [3]	C2593-2	0.04	0.59	26		-30	1.91E+17	4.3	0	2.2	4.3	8.7	-21.3
N12 [3]	C2594-2	0.04	0.63	26		0	1.91E+17	4.3	0	2.2	4.3	8.7	8.7
BEST ESTIMATE CHEMISTRIES from BWRVIP-135 R1													
Plate	A1224-1	0.035	0.65	23		0	1.72E+18	12.3	0	6.1	12.3	24.6	24.6
Weld	5P6214B/0331 Single	0.019	0.828	26.3		-50	1.72E+18	14.0	0	7.0	14.0	28.1	-21.9
Weld	5P6214B/0331 Tandem	0.019	0.828	26.3		-40	1.72E+18	14.0	0	7.0	14.0	28.1	-11.9
Weld AB [2]	4P7216/0156 Single	0.038	0.82	51.4		-40	2.30E+17	9.6	0	4.8	9.6	19.3	-20.7
Weld AB [2]	4P7216/0156 Tandem	0.038	0.82	51.4		-60	2.30E+17	9.6	0	4.8	9.6	19.3	-40.7
INTEGRATED SURVEILLANCE PROGRAM (BWRVIP-135 R1):													
Plate	A1224-1	0.035	0.65		47.87 [4]	0	1.72E+18	25.6	0	8.5	17.0	42.6	42.6
Weld	5P6214B Single	0.019	0.828		38.72 [4,5]	-50	1.72E+18	20.7	0	10.3	20.7	41.3	-8.7
Weld	5P6214B Tandem	0.019	0.828		38.72 [4,5]	-40	1.72E+18	20.7	0	10.3	20.7	41.3	1.3

Notes:
[1] Use of SMAW Heats 422K8511, 627069, 626677, and 627260 was determined to be limited to weld pick-ups at the ID/OD surfaces or initial root pass or sealing at the backing bars which were ground out or subsequently removed. Certified Material Test Reports indicate that no SMAW weld material is present at either the 1/4T or 3/4T location. Therefore, these heats are not required to be evaluated as part of the beltline region.

[2] Weld AB occurs within the extended beltline region, defined as experiencing a fluence >1.0e17 n/cm^2.

[3] The N12 Water Level Instrumentation Nozzle occurs in the beltline region. Because the forging is fabricated from stainless steel, the ART is calculated using the plate heats where the nozzles occur. For GGNS, these nozzles occur in only two (2) of the Shell 2 plates.

[4] The fitted CF (plate material) and adjusted CF (weld material) are determined using the methods defined in RG1.99 R2, Position 2. Best estimate chemistry is considered.

[5] Weld Heat 5P6214B is represented by materials in BWRVIP-135 R1 with two (2) different chemistries. Recommendations provided in BWRVIP-135 R1 have been employed to determine the surveillance chemistry used for calculating the adjusted CF. The adjusted CF is calculated using the best estimate chemistry to represent the vessel CF = (26.3 / 27)* 39.75 = 38.72°F.
[6] Shell #1 is evaluated based on the extended beltline region.
[7] Copper content is not available; therefore, the maximum allowable %Cu was obtained from the vessel design specification.
[8] The plate and axial weld materials are evaluated using the minimum thickness for Shell #1. Circumferential weld AB is evaluated using the smaller thickness between Shell #1 and Shell #2.

GGNS RPV Beltline P-T Curve Input Values

Adjusted RT_{NDT} = Initial RT_{NDT} + Shift	A = 0 + 42.6 = 42.6°F ~43°F (Based on ART values)
Vessel Height	H = 869.75 inches
Bottom of Active Fuel Height	B = 216.3 inches
Vessel Radius (to base metal)	R = 126.69 inches
Minimum Vessel Thickness (without clad)	t = 6.4375 inches

GGNS Definition of RPV Beltline Region[1]

Component	Elevation (inches from RPV "0")
Shell # 2 - Top of Active Fuel (TAF)	366.3"
Shell # 2 - Bottom of Active Fuel (BAF)	216.3"
Shell # 2 – Top of Extended Beltline Region (35 EFPY)	381.7"
Shell # 1 – Bottom of Extended Beltline Region (35 EFPY)	203.4"
Centerline of Recirculation Outlet Nozzle in Shell # 1	172.3"
Top of Recirculation Outlet Nozzle N1 in Shell # 1	197.7"
Centerline of Recirculation Inlet Nozzle N2 in Shell # 1	179.3"
Top of Recirculation Inlet Nozzle N2 in Shell # 1	197.0"
Centerline of 2" Water Level Instrumentation Nozzle in Shell # 2	366.0"

[1] The beltline region is defined as any location where the peak neutron fluence is expected to exceed or equal 1.0e17 n/cm^2.

Based on the above, it is concluded that none of the GGNS reactor vessel plates, nozzles, or welds, other than those included in the Adjusted Reference Temperature Table, are in the beltline region.

Appendix C

GGNS Reactor Pressure Vessel P-T Curve Checklist

Parameter	Completed	Comments/Resolutions/Clarifications
Initial RT_{NDT}		
Initial RT_{NDT} has been determined for GGNS for all vessel materials including plates, flanges, forgings, studs, nuts, bolts, welds. Include explanation (including methods/sources) of any exceptions, resolution of discrepant data (e.g., deviation from originally reported values).	☒	
Appendix B contains tables of all initial RT_{NDT} values for GGNS	☒	
Has any non-GGNS initial RT_{NDT} information (e.g., ISP, comparison to other plant) been used?	☒	Plate Heat A1224-1, weld heat 5P6214B and circumferential weld 4P7216 information obtained from ISP database. Plant specific GGNS information is also used. The data from the ISP results in the limiting beltline ART.
If deviation from the LTR process occurred, sufficient supporting information has been included (e.g., Charpy V-Notch data used to determine an Initial RT_{NDT}).	☒	No deviations from the LTR process.
All previously published Initial RT_{NDT} values from sources such as the GL88-01, RVID, FSAR, etc., have been reviewed.	☒	RVID was reviewed; all initial RT_{NDT} values agreed; no further review was performed. It is also noted that a detailed review of welding records was performed for GGNS. This review determined that heats 627260, 422K8511, 627069, and 626677 were only used for weld pick-ups at the ID/OD surface or initial root pass or sealing at the backing bars, which were ground out or subsequently removed. These materials are not present at the 1/4T or 3/4T locations and therefore are not required for evaluation as beltline materials.
Adjusted Reference Temperature (ART)		
Sigma I (standard deviation for Initial RT_{NDT}) is 0°F unless the RT_{NDT} was obtained from a source other than CMTRs. If σ_I is not equal to 0, reference/basis has been provided.	☒	
Sigma Δ (standard deviation for ΔRT_{NDT}) is	☒	

Parameter	Completed	Comments/Resolutions/Clarifications
determined per RG 1.99, Rev. 2		
Chemistry has been determined for all vessel beltline materials including plates, forgings (if applicable), and welds for GGNS Include explanation (including methods/sources) of any exceptions, resolution of discrepant data (e.g., deviation from originally reported values).	☒	Chemistry data is provided for plant-specific materials and for best-estimate chemistry data obtained from the ISP, and for the representative A1224-1, 5P6214B and 4P7216 materials obtained from the ISP.
Non-GGNS chemistry information (e.g., ISP, comparison to other plant) used has been adequately defined and described.	☒	
For any deviation from the LTR process, sufficient information has been included.	☒	No deviations
All previously published chemistry values from sources such as the GL88-01, RVID, FSAR, etc., have been reviewed.	☒	
The fluence used for determination of ART and any extended beltline region was obtained using an NRC-approved methodology.	☒	
The fluence calculation provides an axial distribution to allow determination of the vessel elevations that experience fluence of 1.0e17 n/cm^2 both above and below active fuel.	☒	
The fluence calculation provides an axial distribution to allow determination of the fluence for intermediate locations such as the beltline girth weld (if applicable) or for any nozzles within the beltline region.	☒	
All materials within the elevation range where the vessel experiences a fluence ≥1.0e17 n/cm^2 have been included in the ART calculation. All initial RT_{NDT} and chemistry information is available or explained.	☒	
Discontinuities		
The discontinuity comparison has been performed as described in Section 4.3.2.1 of the LTR. Any deviations have been explained.	☒	No deviations
Discontinuities requiring additional components (such as nozzles) to be considered part of the beltline have been adequately described. It is clear which curve is used to bound each discontinuity.	☒	

Parameter	Completed	Comments/Resolutions/Clarifications
Appendix G of the LTR describes the process for considering a thickness discontinuity, both beltline and non-beltline. If there is a discontinuity in the GGNS vessel that requires such an evaluation, the evaluation was performed. The affected curve was adjusted to bound the discontinuity, if required.	☒	The thickness discontinuity evaluation demonstrated that no additional adjustment is required; the curves bound the discontinuity stresses.
Appendix H of the LTR defines the basis for the CRD Penetration curve discontinuity and the appropriate transient application. The GGNS evaluation bounds the requirements of Appendix H.	☒	
Appendix J of the LTR defines the basis for the Water Level Instrumentation Nozzle curve discontinuity and the appropriate transient application. The GGNS evaluation bounds the requirements of Appendix J.	☒	

Attachment 8

GNRO-2010/00056

List of Planned Modifications

List of Planned Modifications

Unless otherwise noted the modifications are planned for Refueling Outage 18 (RF018).

AREA IMPACTED BY EPU	RELATED MODIFICATIONS
Entergy Transmission System	Distribution System Upgrades – Required for safe, efficient transfer of additional Grand Gulf Nuclear Station (GGNS) power across Entergy's transmission system – Includes upgrade of breakers, switches, and transmission lines offsite in various substations and switchyards within the Entergy grid Capacitor Bank Installation – Adds reactive power support to meet the power factor design criteria of 0.95 – Capacitor banks to be located at the transmission system load centers adding ~216 MVAR of reactive power
Plant Service Water (PSW) Heat Removal	Radial Well Addition – Results in an increase in the PSW flow margin even though required PSW flow increases – Increases number of PSW pumps from eight to ten Modify PSW Control Valve for the Component Cooling Water (CCW) Heat Exchangers – Additional PSW flow to CCW heat exchangers required during periods of three heat exchanger operation – Existing temperature control valve is not adequately sized for the expected PSW flow increase Re-rate PSW Piping Downstream of the CCW Heat Exchangers – Expected maximum PSW temperature downstream of the CCW heat exchanges increases to 103˚F for EPU – Current rated design temperature for this piping is 100˚F
Reactor Feed Pump Flow	Replace Reactor Feed Pump Turbine Rotors – The increased turbine speed required to meet the limiting EPU feedwater flow conditions results in stresses on the feed pump turbine rotor that exceed the current design Reset the Reactor Feed Pump Overspeed Trip – Estimated reactor feed pump/turbine run-out speed for trip of other feed pump is ~5823. – Resetting overspeed trip to 6100 rpm results in a 4.5% margin between run-out speed and the trip setpoint.

AREA IMPACTED BY EPU	RELATED MODIFICATIONS
Standby Liquid Control (SLC) System Operation	Increase SLC System Boron Enrichment – The cold shutdown boron weight will increase in the equilibrium core design for Extended Power Uprate (EPU) by ~ 18%. – Margin recovery to be achieved by increasing the enrichment of the boron-10 isotope dissolved in the sodium pentaborate solution contained in the SLC storage tank
Instrumentation	Setpoint Adjust/Rescale/Replacement – The instrument modifications identified by the GGNS EPU evaluation are provided in Power Uprate Safety Analysis Report (PUSAR) Table 2.4-2. Condensate Booster Pump Suction Pressure Trip Setpoint – Increased condensate flow results in higher net positive suction head (NPSH) requirements for the condensate booster pumps – Condensate booster pump suction pressure trip setpoint to be increased from 44 psig to 57 psig EPU Vibration Testing Instrumentation Installation – Piping vibration and steam dryer testing require the installation of vibration monitoring instrumentation.
Main Generator Power	Replace Main Generator Current Transformers – The increased output of main generator requires that the associated current transformers be resized. Modify Isophase Bus Duct Cooling – The increased isophase bus current due to EPU will result in exceeding the design limit for both the main bus and the self-cooled delta bus – Replace the isophase bus duct cooler and fans to increase the heat removal capability of the bus duct cooling system for both buses Replace Main Transformers – The existing main transformers are not rated for the expected EPU electrical power output – A spare transformer will also be obtained to minimize outage time in case any main transformer fails Protective Relay Setpoint Recalibration – Changes to the protective relay setpoints for the main unit differential and main transformer differential relays are required due to EPU power output levels and the increased size of the main transformer.

AREA IMPACTED BY EPU	RELATED MODIFICATIONS
Condenser Steam Load	Condenser Tube Staking – Condenser tube vibration is expected to increase at EPU conditions potentially causing tube damage. – Tube staking is used to reduce damaging tube vibration at EPU conditions.
Ultimate Heat Sink (UHS) Heat Removal	Standby Service Water (SSW) Cooling Tower Upgrades – Additional heat removal capability required to remove the decay heat associated with EPU – The ceramic tile fill in the cooling towers replaced with stainless steel fill (completed). Increase UHS Available Water Supply – The SSW cooling tower basins have insufficient water inventory to provide the required cooling for 30 days at EPU conditions. – Extension of the existing siphon that connects the Unit 1 basins with the Unit 2 basins provides the required additional water supply.
Zinc Injection Passivation System	Flow Control Valve Trim Replacement – Current valve would operate at lower range of trim span – Modify to optimize performance and extended valve life Upgrade Strainer – Longer strainer minimizes concerns associated with clogging
Circulation Water System Heat Removal	Auxiliary Cooling Tower Expansion – Increased EPU condenser heat load has potential to result in plant de-rate at high ambient wet bulb temperatures – The addition of eight mechanical draft cooling tower cells to the existing 20 cells ensures a minimal impact to the operating condenser pressure due to EPU. Circulating Water Pump Upgrades – Additional condenser margin is desired to reduce condenser pressure, increase plant output, and reduce condensate temperature – Increased circulating water flow by replacing the pump impellers provides additional condenser margin

AREA IMPACTED BY EPU	RELATED MODIFICATIONS
Main Turbine Generator Capability	Replace High Pressure Turbine – High pressure turbine replacement is required to support the increased steam flow of EPU. – The turbine replacement includes new blading with a flow path design featuring advanced blade profiles designed for the increased mass flow. Seal Oil Skid Replacement/H2 System Upgrade – The increased generator heat caused by EPU power requires generator auxiliary modifications. – The generator hydrogen gas cooling system pressure increase to 75 psig requires an upgrade to the hydrogen seal oil system. Generator / Exciter Cooling – Replacement of generator hydrogen coolers. – Replacement of exciter air coolers. Generator rotor and stator upgrade (1600 Mva)
Heater Drain System Level Control Valves	Upgrade Feedwater (FW) Heater, Moisture Separator Reheater (MSR) Drain Tank, and Heater Drain Tank Level Control Valves – Increased drain flow due to EPU requires modification of several normal and alternate drain valves that are predicted to operate at greater than 80% open.
Moisture Separator Reheater Operation	Replace MSR Shell and Internals – Installed MSR deterioration includes shell thinning, worn tube fins, and an excessive number of plugged tubes. – Current MSR design provides for chevrons that are an old, inefficient design and a two pass reheating design with 10% scavenging steam. – The EPU heat balances were run using new designed efficient chevrons, new tube materials, four pass first and second stage heaters and 2.5% scavenging steam. Replace MSR Relief Valves – Existing relief protection for the MSRs and associated piping must be upgraded for the EPU conditions.
Spent Fuel Pool Heat Removal	Fuel Pool Cooling Heat Exchanger Upgrade – Due to the increased decay heat associated with EPU, the current fuel pool cooling system will not meet the current licensing basis at EPU conditions. – Installation of additional fuel pool cooling system heat removal capability satisfies the current licensing basis requirements and provides post-outage flexibility.

AREA IMPACTED BY EPU	RELATED MODIFICATIONS
Reactor Feedwater Iron Control	Condensate Full Flow Filter (CFFF) Installation – The current 4.8-ppb feedwater combined soluble and insoluble iron concentration is nearly five times higher than the BWRVIP-130 recommended goal. – CFFF installation is anticipated to reduce the feedwater system insoluble iron concentration to less than 1 ppb. Provide Automatic Bypass of CFFF – Loss of a condensate booster pump requires opening of the CFFF bypass to ensure adequate NPSH to the remaining condensate booster pumps. – An automatic interlock to open the bypass valve provides equipment protection during this transient.
Component Cooling Water Heat Removal	Install CCW Heat Exchanger Tube Cleaning System – EPU heat load from the fuel pool cooling heat exchangers requires three CCW heat exchangers to be in operation up to four months after normal refueling. – The inability to remove one CCW heat exchanger from service for periodic cleaning requires the installation of a CCW heat exchanger online tube cleaning system.
Reactor Vessel Steam Dryer Stresses	Replace Steam Dryer – Existing steam dryer does not provide adequate safety margin for the high stress areas at EPU conditions. – Due to the uncertainties associated with dryer modification, the steam dryer will be replaced.
Equipment Qualification Modifications	Replace motor; position and torque switches; and scotch tape splices for 13 RHR motor operated valves Replace hook-up wire for the two hydrogen analyzer panels Scotch tape splices for RHR jockey pump power cables
Power Range Neutron Monitoring System	Install digital replacement for the current Average Power Range Monitor, a subsystem of the Neutron Monitoring System (NMS) (note – a separate License Amendment Request is in NRC review for this system.)

AREA IMPACTED BY EPU	RELATED MODIFICATIONS
Feedwater Heater Operation	Replace Low Pressure Feedwater Heaters – The second stage feedwater heaters are undersized for EPU conditions. – The third and fourth stage feedwater heaters have deteriorated to a point where replacement is considered prudent. Replace Feedwater Heater 5A & 5B Loop Seal Drains – The 5th stage feedwater heater horizontal pipe run just below the heater drain nozzle does not meet industry criteria for a self venting line. Replace 1st, 5th, and 6th Stage Feedwater Heater Vent Orifices – The orifice on the shell side vent of the 1st stage feedwater heater is undersized. – The orifices on the shell side vent of the 5th and 6th feedwater heaters are marginally sized. Replace Liners for the Expansion Joints Located in the Lines to the 2nd Stage Feedwater Heaters – Liners to be replaced due to higher velocities for the EPU condition. – Evaluation of the remaining expansion joints indicates that higher pressure, temperature, and velocity due to EPU are not a concern.

Attachment 9

GRNO-2010/00056

Extended Power Uprate Startup Test Plan

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1.0 INTRODUCTION

This attachment provides detailed information on the testing Entergy Operations, Inc. (Entergy) will perform for the Grand Gulf Nuclear Station (GGNS) Extended Power Uprate (EPU) to 4408 MWt. The planned EPU is approximately thirteen percent (13%) above Current Licensed Thermal Power (CLTP) of 3898 MWt and fifteen percent (15%) above Original Licensed Thermal Power (OLTP) of 3833 MWt. The required modifications to support EPU will be installed during the 2012 refueling outage. Sufficient fuel to support testing and operation at 4408 MWt will also be loaded during the 2012 outage. For implementation of the EPU license amendment, Entergy will conduct a comprehensive startup (SU) test program, as described in this attachment, to demonstrate the safe operation of the plant.

The GGNS startup test program is based on NRC approved General Electric Licensing Topical Reports NEDC-32424P-A, *Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate* (ELTR1); NEDC-32523P-A, *Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate* (ELTR2); and NEDC-33004P-A, *Constant Pressure Power Uprate* (CLTR). In addition, startup test program development followed the guidance provided by Standard Review Plan 14.2.1, *Generic Guidelines for Extended Power Uprate Testing Programs* (SRP 14.2.1).

Section 2.0 of this attachment describes the process used to determine the GGNS EPU testing scope. In accordance with SRP 14.2.1, a comparison of the proposed EPU testing program to the original power ascension test program completed during initial plant licensing was performed (Table 9-1). In addition, the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to anticipated initiating events was evaluated to ensure that the testing program demonstrates adequate implementation of the EPU-related modifications.

The differences between the proposed EPU power ascension test program and the portions of the initial power ascension test program within the SRP 14.2.1 comparison scope are justified in Section 3.0. The Nuclear Regulatory Commission (NRC) did not concur with the CLTR recommendations concerning large transient testing (i.e., testing requiring an automatic scram from high power levels). The NRC determines whether large transient testing is necessary during power ascension to EPU conditions on a plant specific basis. Entergy is requesting NRC concurrence with an exception to large transient testing. Entergy has concluded that GGNS and industry data provide an adequate correlation to allow the effects of the EPU to be analytically determined on a plant specific basis. The justifications for excluding large transient testing are provided in Sections 3.7 and 3.10.

The EPU power ascension test program is provided in Section 4.0. Each EPU related test is described along with the applicable test conditions, the governing procedure(s), and the associated test acceptance criteria. Routine power ascension tests performed in accordance with existing Engineering and Surveillance procedures are provided in Table 9-1.

2.0 TESTING EVALUATIONS

The GGNS EPU test program has been developed to provide assurance that power uprate related modifications to the facility have been adequately constructed and implemented; and the facility can be operated at the proposed EPU conditions in accordance with design requirements and in a manner that will not endanger the health and safety of the public. To accomplish these

goals the test program receives input from the following two sources: the initial test program described in Chapter 14 of the Updated Final Safety Analysis Report (UFSAR) and testing related to the EPU modification scope. Section 2.1 describes the evaluation of the initial test program. Section 2.2 discusses the impact of EPU modifications on the testing scope.

2.1 Comparison to Initial GGNS Startup Test Program

The power ascension test program performed during initial plant licensing and described in Chapter 14.2 of the GGNS UFSAR is evaluated in Table 9-1. Standard Review Plan (SRP) 14.2.1 states that the testing scope to be compared with the proposed EPU testing program shall include power ascension tests initially performed at a power level ≥80 percent of the original licensed thermal power and initial power ascension tests performed at lower power levels if the EPU would invalidate the test results. Any initial power ascension tests within the scope of this comparison that are not included in the EPU testing program must have this deviation adequately justified. In order to determine the testing scope to be compared with the EPU testing program, the original test objective, the test acceptance criteria (see Section 4.0 for definition of Level 1 and Level 2 criteria), and the maximum test performance power level have been provided. Table 9-1 also includes an evaluation of each test to determine if the SRP 14.2.1 criteria for comparison are met. Justification has been provided in Section 3.0 of this attachment for all tests meeting the criteria that are not planned to be performed during EPU implementation.

2.2 Post Modification Testing Requirements

The modifications required to implement EPU are listed in Table 9-2. The majority of these modifications involve secondary plant upgrades to allow GGNS to achieve maximum EPU power. In addition, none of these modifications involve a first of a kind modification to a system important to safety; introduce new system dependencies or interactions; or change system response to initiating events. The post-EPU modification tests generally involve component or system level testing as shown on Table 9-2. Modifications that impact integrated operation of multiple structures, systems, or components are adequately tested by the EPU test program described in Section 4.0 of this attachment.

3.0 JUSTIFICATION FOR ELIMINATION OF POWER ASCENSION TESTS

Several power ascension tests performed at power levels greater than 80 percent during initial plant licensing have not been included in the EPU power ascension test plan. Justification for exclusion of these tests is provided below and typically involves applicability of original power ascension test results to EPU conditions, plant operating experience since original startup, industry operating experience of similar nuclear plants, EPU transient analysis, and/or guidance contained in vendor topical reports. Because no new thermal-hydraulic phenomena or system interactions were introduced as a result of the EPU, these factors did not impact any of the test exclusion justifications.

The GGNS EPU power ascension test plan is based on the testing guidelines established by ELTR1 and CLTR. The NRC concluded that this test program, with the exception of the CLTR proposal to eliminate large transient testing (i.e., MSIV closure and turbine generator load rejection), met the objectives of a suitable test program in that the testing included in the

program provided additional assurance that the constant pressure power uprate (CPPU) design was adequate and provided assurance that the modifications and installation of equipment as part of a CPPU were accomplished in accordance with design. In addition, the NRC stated that they would consider, on a plant-specific basis, the need to conduct these tests and the additional burden that would be imposed on the licensee. The justification to eliminate the large transient testing during the GGNS power ascension is provided in Sections 3.7 (MSIV closure) and 3.10 (turbine generator load rejection). In general, Entergy maintains that this testing is not required for the GGNS EPU because: 1) GGNS has previously performed Large Transient Tests and has documented the results; 2) potential gains from further Large Transient Testing are minimal and produce an unnecessary and undesirable transient cycle on the primary system; 3) analytical methods and training facilities adequately simulate large transient events without the need to impose actual events; 4) plant operators will be trained in potential EPU transient events through the use of simulator models containing Balance of Plant (BOP) transients; and 5) industry operating experience indicates that plants will continue to respond to these transients as designed following EPU implementation. In view of previous test results and the plant response to prior documented events, the EPU startup testing program, as proposed in this attachment, is considered sufficient to validate the continued ability of the plant to safely operate within the required parameters and operational limits.

3.1 Test Number 16A – Selected Process Temperatures

UFSAR Test Description

The adequacy of bottom drain line temperature sensors will be determined by comparing their temperature measurements with the coolant temperature measurements from the recirculation loops when core flow is 100 percent of rated.

During initial heatup while at hot standby conditions, the bottom drain line temperature, recirculation loop suction temperature, and applicable reactor parameters are monitored as the recirculation flow is slowly lowered to either minimum stable flow or the low recirculation pump speed minimum valve position, whichever is greater. The effects of cleanup flow, Control Rod Drive (CRD) flow, and power level will be investigated as operational limits allow. Utilizing this data, it can be determined whether coolant temperature stratification occurs when the recirculation pumps are on and, if so, what minimum recirculation flow will prevent stratification.

Monitoring the preceding information during planned pump trips will determine if temperature stratification occurs in the idle recirculation loops or in the lower plenum when one or more loops are inactive.

All data will be analyzed to determine if changes in operating procedures are required.

Original Startup Test Results

Following the trip of each recirculation pump from Test Condition 6 power (95%-100%), the reactor vessel and recirculation loop temperatures were monitored while in the resulting single loop condition. Temperature stratification did not occur prior to recovery of the idle loop satisfying the Level 1 criteria.

There are no Level 2 criteria associated with this test.

Basis for EPU Test Plan Elimination

Single loop operation following EPU implementation will not result in substantially different reactor coolant flow characteristics. Thus, the original startup test results demonstrating that temperature stratification in the reactor vessel would not occur are still applicable for the uprated condition. Single loop operation will continue to prevent the temperature stratification limits from being reached prior to idle loop recovery.

3.2 Test Number 16B – Water Level Reference Leg Temperature

UFSAR Test Description

The test will be done at rated temperature and pressure and under steady-state conditions, and will verify that the reference leg temperature of the instrument is that value assumed during initial calibration. If not, the instruments will be recalibrated using the measure value. The containment temperatures and drywell temperatures will be monitored during power ascension testing.

Original Startup Test Results

There are no Level 1 criteria associated with this test.

The following Level 2 criteria were met:

- All wide range instruments indicated within 6 inches of the wide range instrument average water level with the limiting instrument reading at the limit.
- All narrow range instruments indicated within 1.5 inches of the narrow range instrument average water level with the limiting instrument reading approximately 1 inch from the average.

Containment and drywell temperatures in the vicinity of the level instrumentation piping were monitored. The average containment temperature of 84°F was well within the acceptable range of 70°F to 95°F. These results confirmed that the instrument calibration assumptions associated with reference leg temperatures were valid.

Basis for EPU Test Plan Elimination

Existing Technical Specification surveillance requirements include instrument channel checks for reactor water level instrumentation associated with Technical Specification functions. These surveillance requirements are performed in accordance with procedure 06-OP-1000-D-0001, *Daily Operating Logs,* and satisfy the intent of the original startup test water level analysis.

Because EPU will not impact drywell or containment average temperatures, the instrument calibration assumptions associated with reference leg temperatures will remain valid and no confirmatory testing is required.

3.3 Test Number 17 – System Expansion

UFSAR Test Description

The thermal expansion tests consist of measuring displacement and temperatures of piping during various operating modes. The first power level used to verify expansion shall be as low as practicable. Thermal movement and temperature measurements shall be recorded during reactor pressure vessel heatup (at least one intermediate temperature); at normal operating temperature of the Reactor Pressure Vessel (RPV), main steam, and recirculation piping; and on three subsequent heatup cooldown cycles.

The piping considered to be within the boundary of this test is as follows:

1. Main Steam: Steam lines, including the Reactor Core Isolation Cooling (RCIC) piping on Line A, shall be tested. Those portions within the scope of the test are bounded by the reactor pressure vessel nozzles and the penetration heat fittings.

2. Relief valve discharge piping: The piping attached to the main steam lines and bounded by the relief valve discharge flange and the first downstream anchor shall be within the scope of the test.

3. Recirculation piping: The recirculation piping, bounded by the reactor pressure vessel nozzles, is within the scope of the test. The RHR suction line from the branch connection to the penetration head fitting shall also be monitored during the tests.

4. Small attached piping: All small branch piping attached to those portions of the preceding piping is within the scope of the test. The small attached piping is bounded by the large pipe branch connection and the first downstream guide or anchor. Small branch pipes that cannot be monitored because of limited access are excluded from the scope of this test.

Original Startup Test Results

Thermal expansion data for the piping within the test scope was obtained at 96% power (OLTP) and 100% core flow. Recirculation suction temperature and feedwater temperature were verified to be within the startup test procedure prerequisite values of 520°F- 540°F and 408°F – 432°F respectively. Average steam line temperature was 538°F. Initial data indicated that there were five (5) Level 1 failures and 17 Level 2 failures. Subsequent analysis determined that all thermal expansion readings were acceptable.

Basis for EPU Test Plan Elimination

EPU will not impact the thermal conditions of any piping within the scope of this test. Recirculation suction temperature is predicted to be 531°F, final feedwater temperature is predicted to be 420°F, and the average steam line temperature change should be insignificant. EPU Startup Test 101 will confirm that these temperatures support the original startup expansion test data. Because operation at EPU conditions will not significantly impact the recirculation, main steam line, or feedwater temperatures, additional startup expansion testing is not required.

3.4 Test Number 23A – Feedwater Pump Trip

UFSAR Test Description

One of the two operating feedwater pumps will be tripped, and the automatic recirculation runback circuit will act to drop the power to within the capacity of the remaining feedwater pump. Prior to the test, a simulation of the feedwater pump trip will be done to verify the runback capability of the recirculation system.

Original Startup Test Results

The 'A' feedwater pump was tripped with reactor power at 95% (OLTP). The Feedwater Control System maintained a margin of 12.9 inches to level 3, well above the Level 2 Acceptance Criteria of greater than a 3 inch margin. The Recirculation Runback feature was actuated 8 seconds into the transient as level dropped below level 4 (approximately 5 inches below normal level). The Recirculation Flow Control Valves closed from 63% to 16% which reduced reactor power to 69% (OLTP), within the capacity of the remaining feedwater pump.

Operating Experience since Startup

On March 22, 2006, the 'A' Reactor Feed pump tripped with reactor thermal power at 100% (~102% OLTP) due to a control system malfunction. Reactor recirculation runback was actuated as expected and the subsequent minimum reactor water level of approximately 25 inches on the narrow range indicator was well above the scram setpoint of 11.4 inches. All other plant equipment responded as expected and reactor power stabilized at 58% following power adjustments to exit the Restricted and Monitored Regions of the Power/Flow Map.

On March 18, 2008, the 'B' Reactor Feed pump tripped with reactor thermal power at 100% (~102% OLTP) due to a spurious hydraulic trip mechanism actuation. Reactor recirculation runback was actuated 7 seconds into the transient and the minimum reactor vessel water level of 22 inches as indicated on a narrow range instrument was reached 21 seconds after the feed pump trip. All other plant equipment responded as expected and reactor power was stabilized at 55%.

EPU Transient Analysis Results

A Single Feedwater Pump Trip (SFWPT) analysis was performed as an operational assessment to determine the ability to avoid a scram on low level. The transient is considered to have adequate margin to scram avoidance if the margin is at least three inches to the scram setpoint. The SFWPT event was analyzed for GGNS at EPU Rated power and a conservatively low initial core flow with a single feedwater pump capacity of 81% of EPU rated steam flow. This analysis resulted in a minimum margin to the Level 3 scram setpoint greater than 10 inches.

Basis for EPU Test Plan Elimination

Based on plant historical data and EPU analytical results, the capability of the recirculation system to prevent a low water level scram following the trip of a feedwater pump is preserved. Because scram avoidance is not a regulatory requirement, additional plant testing to demonstrate that a feedwater pump trip does not result in a reactor scram is not warranted.

3.5 Test Number 23C – Loss of Feedwater Heating

UFSAR Test Description

The condensate/feedwater system will be studied to determine the single failure that will cause the largest loss in feedwater heating. This event will then be performed between 80 and 90 percent power with the recirculation flow near its rated value.

Original Startup Test Results

With the 6A feedwater heater out of service, steam to the 6B feedwater heater was isolated from an initial reactor power level of 84%. Reactor power increased to 90% and the following Level 1 criteria were met: (1) Feedwater temperature decrease ≤100°F with an actual decrease of 44.4°F; (2) The Minimum Critical Power Ratio (MCPR) remained greater than the safety limit of 1.06 with a final value of 1.429; and (3) The actual increase in simulated heat flux of 90.7% did not exceed the predicted Level 2 value of 90.8% by more than 2%. In addition, the Level 2 criteria for the actual increase in simulated heat flux did not exceed its predicted value referenced to the actual feedwater temperature change and power level.

Operating Experience since Startup

Reduction in Feedwater Temperature events periodically occur at GGNS, causing entry into the loss of feedwater heating Off-Normal Event Procedure (ONEP). Power is reduced and plant conditions stabilized prior to recovery of the affected heaters. Although most of these events are not true Loss of Feedwater Heating events as defined by the UFSAR, they demonstrate that there has been no significant safety consequences associated with these events and there have been no violations of cladding integrity limits or other fuel design limits.

EPU Transient Analysis Results

The worst case Loss of Feedwater Heating (LFWH) event for GGNS continues to be the loss of high pressure feedwater heaters 6A and 6B. An analysis was performed to evaluate this transient at EPU conditions. The predicted reduction in feedwater temperature for EPU is ~88°F which remains below the original acceptance criteria of 100°F. A LFWH transient analysis is also performed with each reload analysis to determine if LFWH will become a limiting transient event (Refer to PUSAR Section 2.8.5.1).

Basis for EPU Test Plan Elimination

Testing the loss of feedwater heating is not required because the original acceptance criterion of ≤ 100°F continues to be met under EPU conditions. Reduction in feedwater temperature events occur from time to time and are relatively minor transients. Operators are trained on feedwater heater events using the plant simulator and EPU will not significantly impact the required plant response. Consequently, it is not necessary to test feedwater heater losses as part of EPU power ascension.

3.6 Test Number 25A – MSIV Functional Tests

UFSAR Test Description

At 5 percent and greater reactor power levels, individual fast closure of each Main Steam Isolation Valve (MSIV) will be performed to verify its functional performance and to determine closure times. The MISV closure times will be determined from the Main Steam Line (MSL) isolation data.

To determine the maximum power level at which full individual closures can be performed without a scram, first actuation will be performed between 40 and 65 percent power and used to extrapolate to the next test point between 60 and 85 percent power, and ultimately to the maximum power test condition with ample margin to scram.

Original Startup Test Results

Fast closure times for each MSIV were determined during individual valve closures and during the full isolation test (Test Number 25B). Closure times ranged between 3.52 seconds and 3.88 seconds exclusive of delays which met the Level 1 criteria of between 3 seconds and 5 seconds. The longest closure time including all delays was 4.86 seconds which met the Level 1 criteria of less than 5.5 seconds.

Individual MSIV fast closures were performed from an initial power of 84.2%. The following Level 2 criteria were met: peak vessel pressure remained 10 psi below scram; peak neutron flux remained 7.5 percent below scram; steam flow in individual lines remained 10 percent below the isolation trip settings; and the peak heat flux remained 5 percent less than its trip point. This test determined that the maximum power level at which full individual closures can be performed without a scram was 84.2% due to vessel pressure reaching its margin limit.

Basis for EPU Test Plan Elimination

The EPU impact to the MSIV closure times is discussed in Section 2.2.2.2.1.2 of the Power Uprate Safety Analysis Report (PUSAR) which is Attachment 5 of this license amendment request (LAR).

The steam flow at 84.2% of original licensed thermal power is equivalent to the steam flow at 73.2% EPU thermal power. Because the limiting parameter at this steam flow is high vessel pressure which is not impacted by EPU, the maximum power level at which full individual closures can be performed without a scram has already been determined for EPU conditions (i.e., 73.2%); therefore, additional testing is not required.

3.7 Test Number 25B – Full Reactor Isolation

UFSAR Test Description

A test of the simultaneous full closure of all MSIVs will be performed at 95 to 100 percent of rated thermal power. Correct performance of the RCIC and relief valves will be shown. Reactor process variables will be monitored to determine the transient behavior of the system during and following the main steam line isolation.

Original Startup Test Results

An inadvertent reactor full isolation occurred at 75% power and 100% core flow that fulfilled all of the objectives of the planned isolation from full power. An NRC letter dated May 13, 1985, 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% power isolation data analysis.

Based on the inadvertent isolation analysis, the following Level 1 criteria were met: flooding of the main steam lines was prevented as demonstrated by a maximum upset range water level reading of 86.25 inches against a limit of 101 inches; the positive change in vessel dome pressure occurring within 30 seconds after closure of all Main Steam Isolation Valves was 113.5 psig with did not exceed the Level 2 criteria of 125 psig by more than 25 psig; and the positive change in simulated heat flux was 0% which did not exceed the Level 2 criteria of 0.1% by more than 2%.

As shown by the previous data, the Level 2 criteria for the positive change in vessel dome pressure and simulated heat flux were also met. Because reactor vessel water level did not reach the initiation setpoint, the Level 2 criteria associated with the automatic initiation of RCIC and High Pressure Core Spray (HPCS) were not tested; however, RCIC was manually initiated to adequately control vessel water level during the transient.

Industry Operating Experience

Nine Mile Point Unit 2

Nine Mile Point Unit 2 (NMP2) is a General Electric (GE) BWR-5 reactor similar in design to GGNS. The following information was provided in their EPU licensing application dated 05/27/2009 (ML091610105).

On October 15, 2001, while operating at approximately 104% OLTP (100% CLTP) power, NMP2 experienced a scram when all MSIVs went closed. The event was the result of human performance error while restoring a steam flow transmitter to service causing the high steam flow instrumentation to actuate.

On November 11, 2002 while operating at approximately 104% OLTP (100% CLTP) power, NMP2 experienced a scram when all MSIVs went closed. The event was the result of an MSIV disc separating from the valve stem, causing a rapid flow reduction in one of the main steam lines.

The review of the plant response compared to the Updated Safety Analysis Report (USAR) Section 15.2.4 transient analysis for both of these events confirms that they are bounded by the USAR analysis as evidenced by the following:

- Actual neutron flux was less than predicted.
- Actual peak pressure was less than predicted.
- Only Group 1 Main Steam Safety Relief Valves (SRVs) lifted (analysis predicts all 5 groups lift).
- The first event was classified as a full MSIV closure resulting in a Reactor Protection System Scram on MSIV position.
- The second event more closely followed the single MSIV closure classification resulting in a Reactor Protection System Scram on high reactor pressure.
- In both events reactor water level was controlled manually. The initial level response was comparable to that predicted in the USAR analysis. Within minutes of event initiation, reactor water high level trips are expected because SRV pressure control swells RPV level to above the Level 8 trip setpoint. RCIC is the preferred level control method for this event.
- In both events the Recirculation Pumps transferred to the low frequency motor generators (LFMGs) as designed.

Clinton Power Station

The Clinton Power Station is the same general reactor design as GGNS (GE BWR-6). On December 18, 2000 a full MSIV closure occurred from 100% power due to inadequate indication of an existing fault during performance of a surveillance test (Ref., Clinton Power Station LER 2000-07 – ADAMS Accession Number ML021910013). The RCIC system was manually actuated to control water level. There were no emergency core cooling system actuations and the safety relief valves were utilized for pressure control.

River Bend Nuclear Station

River Bend Nuclear Station (RBS) is the same general reactor design as GGNS (GE BWR-6). On December 4, 1994 an inadvertent full MSIV closure occurred from 100% power due to a human performance error during the performance of a surveillance test. An evaluation determined that operator actions during the scram were appropriate and that safety systems functioned as designed including the automatic actuation of four SRVs.

<u>EPU Transient Analysis Results</u>

The Main Steam Isolation Valve Closure with Scram on High Flux (MSIVF) is the limiting overpressure protection event. The overpressure analysis description and methodology are described in ELTR1. The analysis assumes event initiation with a peak reactor

dome pressure of 1060 psia, seven SRVs out of service, and RTP at 102% of EPU RTP. The calculated peak RPV pressure is 1334 psig and the corresponding calculated maximum reactor dome pressure is 1302 psig. The peak reactor vessel pressure remains below the American Society of Mechanical Engineers (ASME) limit of 1375 psig and the peak dome pressure remains below the Technical Specification Safety Limit of 1325 psig. The results of the EPU overpressure protection analysis for the GGNS MSIVF event are consistent with the generic analysis in ELTR2. The GGNS response to the MSIVF event is provided in Section 2.8.4.2 and Figure 2.8-20 of the PUSAR (Attachment 5).

The MSIVF results are conservative when compared to the plant response expected during a full MSIV isolation power ascension test. The MSIV Closure Event with Scram due to Valve Position (MSIVD) is more representative of the Full Reactor Isolation startup test. A comparison of the MSIVD evaluation at EPU power with the Level 1 testing criteria demonstrates acceptable predicted test results with adequate reactor water level margin to the main steam lines, a peak reactor dome pressure of 1174 psig, and a heat flux increase of 0%.

Basis for EPU Test Plan Elimination

MSIV full closure testing at 100% rated power during EPU power ascension testing is not required at GGNS because the plant response at EPU conditions is expected to be similar to the documented response during initial startup testing. The transient analysis performed for the GGNS EPU demonstrates that all safety criteria are met. Deliberately closing all MSIVs from 115% OLTP power will result in an undesirable transient cycle on the primary system that can reduce equipment service life. As demonstrated during initial startup testing and confirmed by analysis, all equipment responses to the transient are within component and system design capabilities. However, placing accident mitigation equipment into service, under maximum loading conditions, uses available service life. Equipment service life should be retained for actual events rather than for demonstration purposes. Additional transient testing and the resulting impact will provide no additional plant response information beyond that documented during startup testing and from the evaluation of actual industry events. These events demonstrate the analysis is conservative and actual events will not challenge safety or design limits for this event.

Based on plant historical data and EPU analytical results, the MSIV Closure Event results in conditions that are within design limits. In addition, no new design functions in safety-related systems are required that would need large transient testing validation for EPU. No physical modification or setpoint changes are made to the SRVs. No new systems or features are installed for mitigation of rapid pressurization events analyzed for EPU. The increase in steam flow and its impact is not significant with regard to the reactor pressure transient response. The EPU impact to the feedwater system does not adversely change the feedwater level control response and the use of RCIC as the preferred level control system for this event.

In view of the above, the objective of determining reactor transient behavior resulting from the simultaneous full closure of all MSIVs can be satisfied for EPU through analysis without performing large transient testing. In addition, the limiting transient analyses are included as part of the cycle specific reload licensing analysis. This test does not need

to be repeated at EPU conditions because plant response is not expected to significantly change from that previously documented at CLTP conditions. Plant performance and analyses show adequate margins are available in vessel pressure and level limits that demonstrate acceptable reactor transient behavior.

3.8 Test Number 25C – Main Steam Line Flow Venturi Calibration

UFSAR Test Description

Beginning at approximately 40 percent core thermal power, pertinent plant data will be taken along the 75 percent rod line at selected power levels. The same process will be repeated along the 100 percent rod line. The accumulated data will then be compared against the calibration curves and a known flow source to verify that acceptable steam flow measurements have been made.

Original Startup Test Results

There were no Level 1 criteria associated with this test.

The following Level 2 criteria were met: the differential pressure reading of all main steam line flow trip units was greater than 79.3 psid at rated steam flow with a low reading of 82 psid; the accuracy of the main steam line flow venturis relative to the calibrated feedwater flow was within ±5% of rated flow at flow rates between 20% and 120% of rated. The repeatability/noise was within ±15% of rated flow with actual measurements less than 1% of rated flow at all flow levels.

Basis for EPU Test Plan Elimination

The initial power ascension testing confirmed proper operation of the main steam line flow elements to a power level greater than EPU power. No physical changes to these flow elements have been made as a result of EPU. Instrument channel checks, periodic heat balances, and operator observations will ensure the continued accuracy of these instruments at EPU power.

3.9 Test Number 26 – Relief Valves

UFSAR Test Description

A functional test of each safety relief valve (SRV) shall be made as early in the startup program as practical. This is normally the first time the plant reaches 250 psig. The test is then repeated at rated reactor pressure. Bypass valves (BPV) response is monitored during the low pressure test and the electrical output response is monitored during the rated pressure test. The test duration will be about 10 seconds to allow turbine valves and tailpipe sensors to reach a steady state.

The tailpipe pressure sensor responses will be used to detect the opening and subsequent closure of each SRV. The BPV and electrical output responses will be analyzed for anomalies indicating a restriction in an SRV tailpipe. In addition GGNS will measure SRV tailpipe backpressure on the longest and shortest tailpipes.

Valve capacity will be based on certification by ASME code stamp with the applicable documentation being available in the on-site records. Note that the nameplate capacity/pressure rating assumes that the flow is sonic. This will be true if the back pressure is not excessive.

A major blockage of the line would not necessarily be offset and it should be determined that none exists through the BPV response signatures.

Vendor bench test data of the SRV opening responses will be available on-site for comparison with design specifications.

During pressurization transients such as MSIV full closures and turbine trips/generator load rejection the operation of the safety grade low-low pressure relief logic system will be monitored. A comparison between the reactor pressure behavior and SRV actuations will be made to confirm open/close set points and containment load mitigation through the prevention of subsequent simultaneous SRV actuations. Recirculation drive flow, loop vibration, and pump head should be recorded for one pump as a non-cavitation check during low-low SRV action.

Original Startup Test Results

Relief valve operation was observed during the large transient testing (i.e., MSIV full isolation and generator load reject). During the MSIV full isolation from an initial power level of 75%; RPV peak pressure was 1104 psig, two SRVs opened to control RPV pressure initially, and one SRV cycled three additional times at the low-low set values. During the generator load reject with one turbine bypass valve out of service from an initial power level of 100%; RPV peak pressure was 1109 psig, six SRVs opened to control RPV pressure initially, and no subsequent SRV actuations were observed as pressure did not reach the low-low set opening value following the initial actuation. The successful functional tests of the low-low set pressure relief logic met the Level 1 criteria associated with this test. Test exceptions were required for the Level 2 criteria related to relief valve closure due to improper testing methodology and relief valves that were weeping. All test exceptions were resolved based on other indications of proper relief valve closure.

Operating Experience since Startup

On March 21, 2008, while operating at approximately 102% OLTP (100% CLTP), GGNS experienced a scram when the main generator tripped (i.e., generator load reject). The event was caused by the actuation of the “C” phase unit differential lockout. At the time of the event, one turbine bypass valve was out of service. Results were very similar to the original startup test results with a RPV peak pressure of 1113 psig, six initial SRV actuations, and no subsequent actuations as the pressure did not reach the low-low set opening value following the initial actuation. All SRVs indicated closed within the low-low set closing tolerances.

Basis for EPU Test Plan Elimination

Original startup testing and data gathered during the load rejection event in 2008 confirm that the SRVs operate in accordance with their design requirements. EPU does not

impact RPV pressure and does not require SRV modifications or setpoint changes. For this reason, the CLTR does not include SRV testing in its standard set of tests that were established for the initial EPU power ascension.

3.10 Test Number 27 – Turbine Trip and Generator Load Rejection

UFSAR Test Description

Turbine trip and generator load rejection will be performed at selected power levels during the Startup Test Program. At low power levels (<40 percent), reactor protection is provided by high neutron flux and high vessel pressure scrams. At higher power levels, the reactor will scram by sensing loss of stop and control valve hydraulic fluid pressure in anticipation of valve closure. Backup scram action is provided by high neutron flux and high vessel pressure.

A generator load rejection will be performed at low power level such that nuclear boiler steam generation is just within bypass valve capacity to demonstrate scram avoidance. For this test, the recirculation system is in manual, and the operator may intervene to prevent high or low water level scrams. At an intermediate power level, in excess of bypass capacity, a turbine trip will be performed, and the response of the plant to this trip and scram will be determined.

As 100 percent power is approached, there is little difference for a partial bypass valve capacity plant in the reactor pressure transient response to a generator or turbine trip event. However, the accident analysis shows the generator trip is the more limiting of the two. Additionally, for the GGNS breaker-and-a-half switchyard design, there is no automatic station service power switching which sometimes causes a different plant response to the turbine or generator trip at other BWRs. For these reasons and since the residual steam in the turbine may cause a slight overspeed, a generator trip at 100 percent power will be performed at GGNS.

Original Startup Test Results

A generator load rejection was initiated from 100% reactor thermal power and 98% core flow. Due to the ‘A’ bypass valve being out of service, the transient was performed with only two of the three bypass valves operable. The Level 1 criteria associated with bypass valve timing were resolved as acceptable based on bypass valves ‘B’ and ‘C’ meeting the criteria and the satisfactory performance of bypass valve ‘A’ during the Test Condition 3 test. The peak upset range water level reading was 68.3 inches which was well below the Level 1 criterion of 101 inches for steam line flooding prevention. The recirculation pump drive flow coastdown transient was not within the Level 1 criteria curves contained within the startup test; however, a General Electric evaluation concluded that the results were acceptable based on an insignificant impact on the Chapter 15 UFSAR transient analysis.

The Level 1 (<139.1 inches) and Level 2 (<114.1 inches) criteria for positive change in vessel dome pressure occurring within 30 seconds were met with a pressure rise of 88.0 psi. The Level 1 (≤2%) and Level 2 (≤0%) criteria for positive change in simulated heat flux were also met with a heat flux rise of 0%.

The Level 2 criterion associated with the feedwater level control system avoiding loss of feedwater due to a high level trip was not met as the feedwater pumps tripped approximately 80 seconds into the transient due to high reactor pressure vessel water level. General Electric Engineering reviewed this failure and concluded that while the system controls were not optimal, they were adequate for reliable plant operation. This conclusion was based on the fact that the feedwater control system maintained level above the RCIC, HPCS, and Recirculation Pump trip setpoints and below the main steam lines. For these reasons, the system performance was accepted with this deviation.

The remaining Level 2 criteria were satisfied as follows:

- There was no MSIV closure during the first three minutes of the transient and operator action was not required during that period to avoid the MSIV trip.
- Low water level total recirculation pump trip, HPCS, and RCIC were not initiated.
- The recirculation low frequency motor generator sets took over after the initial recirculation pump trips and adequate vessel temperature difference was maintained.

Industry Operating Experience

On July 4, 2002, the Clinton Power Station tripped from 95% rated thermal power (114% OLTP) as a result of a faulty main power transformer sudden pressure relay (SPR) actuation. The SPR initiated a generator trip and lockout, resulting in a reactor scram. The plant responded normally to the scram. As expected, reactor water level initially lowered below the Low Level 3 trip point and was restored in accordance with operating procedures. There was no MSIV isolation or safety relief valve actuation during the event. The response and behavior of the plant during the event were compared to the Generator Load Rejection transient discussed in Chapter 15 of the Updated Safety Analysis Report and the General Electric Transient Safety Analysis Report and were determined to be within those analyses. Like GGNS, Clinton Power Station is a GE BWR-6 design. At the time of the event, Clinton had implemented a 20% EPU. (Ref., Clinton Power Station LER 2002-03 – ADAMS Accession Number ML022480344)

Operating Experience since Startup

On March 21, 2008, while operating at 100% power (~102% OLTP), GGNS experienced a scram when the main generator tripped (i.e., generator load reject). The event was caused by the actuation of the “C” phase unit differential lockout. At the time of the event, the ‘C’ turbine bypass valve was out of service. The prompt opening of the ‘A’ and ‘B’ turbine bypass valves along with the actuation of six SRVs limited peak steam dome pressure to 1113 psig from an initial value of 1038 psig (i.e., a pressure rise of 75 psi). Reactor vessel water level remained below the RFPT trip setpoint with the indicated wide range water level reaching a maximum level of 49 inches prior to the manual tripping of the ‘A’ RFPT approximately 2.5 minutes into the transient in accordance with plant procedures. In addition, the low water level total recirculation pump trip, HPCS, and RCIC were not initiated as the minimum indicated water level was

6 inches on the wide range instruments. The reactor recirculation pumps tripped to the low frequency motor generator sets as designed.

Basis for EPU Test Plan Elimination

NRC-approved Licensing Topical Report NEDC-32323P-A, *Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate* (ELTR-1), states that a Generator Load Rejection test, equivalent to that conducted in the initial startup testing, will be performed if the power uprate is more than 15% above any previously recorded Generator Load Rejection transient data. As described above, GGNS experienced a Generator Load Rejection transient on March 21, 2008 while operating at 100% CLTP (3898 MWT). The GGNS EPU proposes a power increase to 4408 MWT (a thermal power increase of 13% above CLTP) which is less than the ELTR-1 criteria of 15% above a previously recorded Generator Load Rejection transient. All observed plant parameters during the transient were within the expected plant response defined by the UFSAR testing criteria.

Clinton Power Station, which is a very similar design to GGNS (i.e., a General Electric BWR-6), experienced a Generator Load Rejection at 95% rated thermal power. Because Clinton Power Station had implemented a 20% EPU, this power level corresponds to 114% OLTP which is comparable to the proposed GGNS EPU percent power. The response and behavior of the plant during the event were determined to be within the Generator Load Rejection transient discussed in Chapter 15 of Clinton's Updated Safety Analysis Report and the General Electric Transient Safety Analysis Report.

3.11 Test Number 29A – Recirculation Valve Position Control

UFSAR Test Description

The testing of the Recirculation Flow Control System follows a "building block" approach while the plant is ascending from low- to high-power levels. Components and inner control loops are tested first, followed by drive flow control and plant power maneuvers to adjust and then demonstrate the outer loop controller performance. While operating at low power, with the pumps using the low frequency power supply, small step changes will input into the position controller and the response recorded.

Original Startup Test Results

The individual recirculation valve position control loop response was observed at 50% core flow, 75% core flow, and 100% rated power for both the 'A' and 'B' recirculation flow control valve position controllers. All necessary adjustments were completed to ensure satisfactory response at each of these plant conditions.

Basis for EPU Test Plan Elimination

Original startup testing confirmed that the recirculation valve position control system operates in accordance with its design requirements. The projected increase in recirculation flow rate is 1.2%. Due to the small increase in recirculation flow rate, the plant response to a recirculation flow change is not significantly affected. For this reason, the CLTR does not include recirculation controller testing in its standard set of tests that were established for the initial EPU power ascension.

3.12 Test Number 29B – Recirculation Flow Loop Control

UFSAR Test Description

Following the initial position mode tests of Test 29A, the final adjustment of the position loop gains, flow loop gains, and preliminary values of the flux loop adjustments will be made on the mid-power line. This will be the most extensive testing of the recirculation control system. The core power distribution will be adjusted by control rods to permit broader range of maneuverability with respect to PCIOMR. In general, the controller dials and gains will be raised to meet the maneuvering performance objectives. Thus, the system will be set to be the slowest that will perform satisfactorily, in order to maximize stability margins and to minimize equipment wear by avoiding controller over activity.

Original Startup Test Results

The automatic flow control and neutron flux control responses were observed at established plateaus between 50% and 100% core flow. All necessary adjustments were completed to ensure satisfactory response at each of these plant conditions.

Basis for EPU Test Plan Elimination

Original startup testing confirmed that the recirculation flow control and neutron flux control systems operate in accordance with their design requirements. The projected increase in recirculation flow rate is 1.2%. Due to the small increase in recirculation flow rate, the plant response to a recirculation flow change is not significantly affected by EPU. For this reason, the CLTR does not include recirculation controller testing in its standard set of tests that were established for the initial EPU power ascension. In addition, UFSAR Section 5.4.1.6.4.3 states that the automatic flow control and the neutron flux loop have been disabled.

3.13 Test Number 30A – One Recirculation Pump Trip

UFSAR Test Description

Single recirculation pump trips will be made at designated power levels. Reactor operating parameters, such as water level, simulated heat flux, and APRM level will be recorded during the transient to determine margins with respect to limits.

Original Startup Test Results

Each recirculation pump was tripped and subsequently recovered from an initial reactor power level of 100%. There were no Level 1 criteria associated with this test.

The following Level 2 criteria were met: the reactor water level margin to avoid a high level trip was greater than 3.0 inches (6.7 inches for the ‘A’ pump and 6.4 inches for the ‘B’ pump); the simulated heat flux margin to avoid a scram was greater than 5.0 percent during the one-pump trip (9.0 percent for the ‘A’ pump and 11.2 percent for the ‘B’ pump) and the recovery from the one-pump trip (18.4 percent for the ‘A’ pump and 20.3 percent for the ‘B’ pump); the APRM neutron flux margin to avoid a scram was greater than 7.5

percent during the one-pump trip recovery (48.6 percent for the 'A' pump and 53.4 percent for the 'B' pump); and the time from zero pump speed to full pump speed was greater than 3.0 seconds (5.5 seconds for the 'A' pump and 5.9 seconds for the 'B' pump).

Basis for EPU Test Plan Elimination

Original startup testing confirmed that the plant response following a single recirculation pump trip met all design requirements. The projected increase in recirculation flow rate is 1.2%. Due to the small increase in recirculation flow rate, the plant response to a recirculation flow change is not significantly affected. For this reason, the CLTR does not include recirculation pump trip testing in its standard set of tests that were established for the initial EPU power ascension.

3.14 Test Number 30B – RPT Trip of Two Recirculation Pumps

UFSAR Test Description

Both recirculation pumps are tripped at the designated power level, and the flow coastdown transient is recorded.

Original Startup Test Results

Both recirculation pumps were simultaneously tripped from a reactor power level of 98% and a core flow of 108%. The Level 1 criterion stating that the two-pump drive flow coastdown transient during the first 3 seconds must be bounded by the curves specified on UFSAR Figure 14.2-6, adjusted for transmitter time delay and time constant, was not met. The coastdown flow rate was within the criteria curves for the first 0.5 seconds; however, it was faster than the 4.0 second pump inertia curve after 0.5 seconds. General Electric Engineering analysis of the test results determined that the deviation in recirculation pump coastdown flow would not affect the ECCS and transient safety limits.

Basis for EPU Test Plan Elimination

Original startup testing confirmed that the plant response to the RPT trip of both recirculation pumps trip did not impact ECCS or transient safety limits. The projected increase in recirculation flow rate is 1.2%. Due to the small increase in recirculation flow rate, the plant response to a recirculation flow change is not significantly affected. For this reason, the CLTR does not include recirculation pump trip testing in its standard set of tests that were established for the initial EPU power ascension. In addition, the original startup testing was performed from a core flow of 108%. Because this flow rate is greater than the licensed EPU core flow rate, the original test results would satisfy any EPU testing requirement.

3.15 Test Number 30C – Reactor Recirculation System Performance

UFSAR Test Description

Recirculation system parameters will be recorded at several power-flow conditions and in conjunction with single-pump trip recoveries and internals vibration testing.

Original Startup Test Results

Recirculation system data was taken during: (1) steady-state conditions between 102.5% core flow and minimum flow control valve position; (2) single recirculation pump recoveries; and (3) internals vibration testing at maximum core flow (107.6%) and 100% core thermal power. The following Level 2 criteria were met: the core flow shortfall of 1.8% did not exceed the 5 percent criterion at rated power and the recirculation drive flow shortfall of 0% for each loop did not exceed the 5 percent criterion at rated power.

Basis for EPU Test Plan Elimination

Original startup testing demonstrated that the recirculation system parameters conformed to recirculation system design requirements. The projected increase in recirculation flow rate is 1.2%. Due to the small increase in recirculation flow rate, the plant response to a recirculation flow change is not significantly affected. For this reason, the CLTR does not include recirculation system monitoring in its standard set of tests that were established for the initial EPU power ascension. In addition, steady-state monitoring was performed at a core flow of 107.6%. Because this flow rate is greater than the licensed EPU core flow rate, the original test results would satisfy any EPU steady-state monitoring test requirement.

3.16 Test Number 33 – Drywell Piping Vibration

UFSAR Test Description

The piping considered to be within the scope of testing:

1. Main Steam: Steam lines, including the RCIC piping on Line A, shall be tested. Those portions within the scope of the test are bounded by the reactor pressure vessel nozzles and the penetration heat fittings.

2. Relief valve discharge piping: The piping attached to the main steam lines and bounded by the relief valve discharge flange and the first downstream anchor shall be within the scope of the test.

3. Recirculation piping: The recirculation piping, bounded by the reactor pressure vessel nozzles, is within the scope of the test. The RHR suction line from the branch connection to the penetration head fitting shall also be monitored during the tests.

4. Small attached piping: All small branch piping attached to those portions of the preceding piping is within the scope of the test. The small attached piping is bounded by the large pipe branch connection and the first downstream guide or anchor. Small branch pipes that cannot be monitored because of limited access are excluded from the scope of this test.

Because of limited access due to high-radiation levels, no visual observation is required during the startup phase of the testing. Remote measurements of piping vibrations shall be made during the flowing steady-state conditions:

1. Recirculation flow at minimum flow
2. Recirculation flow at 50 percent of rated
3. Recirculation flow at 75 percent of rated
4. Recirculation and main steam flow at 100 percent of rated
5. RCIC turbine steam line at 100 percent of rated
6. RHR suction piping at 100 percent of rated flow in shutdown cooling mode

During the operating transient load testing, the amplitude of displacement and number of cycles per transient of the main steam and recirculation piping will be measured, and the displacements compared with acceptance criteria. Remote vibration and deflection measurements shall be taken during the following transients:

1. Recirculation pump start
2. Recirculation pump trip at 100 percent of rated flow
3. Turbine control valve closure at 100 percent power
4. Manual discharge of each SRV valve at 1,000 psig and at planned transient tests that result in SRV discharge.

For the locations to be monitored, predicted displacements and actual measurements will be compared.

Original Startup Test Results

Vibration data for the piping within the scope of this test was taken during the following steady state and transient conditions: (1) Reactor core flow at steady state rated conditions (99.4%) and power at 95.4% of rated; (2) Trip of the 'B' recirculation pump with initial core flow at 107.6% and reactor power at 99.8%; (3) Dual recirculation pump trip with initial core flow at 108.4% and reactor power at 98.3%; (4) Generator load rejection with initial core flow at 97.6% and reactor power at 99.6%; and (5) Maximum core flow conditions with core flow at 107.5% and power at 99.4%. All vibration levels were either within the associated testing Level 1 and Level 2 criteria or found to be acceptable following engineering evaluation.

Basis for EPU Test Plan Elimination

Steady-state vibration testing will be performed for the Main Steam piping impacted by EPU (see Section 4.10 and Attachment 10 for a description of this testing). Vibration measurements for transient conditions (i.e., SRV actuation and recirculation pump trips)

and steady-state recirculation piping vibration measurements are not included in the EPU testing scope. EPU does not impact RPV pressure and does not require SRV modifications or setpoint changes. For this reason, the CLTR does not include SRV testing in its standard set of tests that were established for the initial EPU power ascension. In addition, recirculation system transient and steady-state vibration monitoring were performed at a core flow that was greater than the licensed EPU core flow. For this reason, the original test results satisfy the EPU recirculation vibration monitoring test requirements.

3.17 Test Number 34 – Vibration Measurements

UFSAR Test Description

Vibration amplitudes and frequencies obtained from the sensors mounted on the various reactor internal components will be monitored and recorded. The measured amplitudes and frequencies are then compared to the acceptance criteria to ensure that all measured vibration amplitudes are within acceptable levels.

The test program consists of preoperational tests, precritical tests, and hot power tests performed with the system at normal operating pressure and temperature.

Sensors used for the measurements are resistance wire strain gages, displacement sensors, and accelerometers with double integrating output signal conditioning. Sensors will be installed in a manner to indicate the most probable mode of vibration as indicated by analysis.

Original Startup Test Results

Vibration data was taken during operation on the 100% load line from minimum to maximum core flow. This included all the pump trip events ranging from single pump trips to dual pump trips caused by main generator load rejection and those initiated by the RPT circuitry. All operable sensors responded within the bounds of acceptance criteria with substantial margins. The highest peak-to-peak stress amplitude was 83% of criteria on the jet pump diffusers at maximum core flow (107.6%) and 100% core thermal power.

Basis for EPU Test Plan Elimination

Analysis of the EPU impact on the flow-induced vibration (FIV) to the reactor internal components is contained in PUSAR Section 2.2.3 (Attachment 5). In addition, the reactor internal component vibration monitoring was performed up to a core flow of 107.6%. Because this flow rate is greater than the licensed EPU core flow rate, the original test results would satisfy any EPU internal component monitoring test requirement for those components impacted by core flow.

3.18 Test Number 72 – Drywell Cooling System

UFSAR Test Description

During heatup and power operation, data will be taken to ascertain that the drywell

atmospheric conditions are within design limits.

Original Startup Test Results

There were no Level 1 criteria associated with this test.

Steady-state operation data collection was conducted with the reactor at 99% power. The Drywell Cooling System demonstrated the ability to maintain the design conditions in the drywell under standard operating conditions while using the full redundancy of the system's coils and fans. All parameters monitored were within the Level 2 acceptance criteria limits.

Post-scram operation data collection was performed following the reactor scram initiated by the generator load rejection test. The Drywell Cooling System continued to demonstrate the ability to maintain the design conditions in the drywell following the scram. All parameters were within the Level 2 acceptance criteria limits.

Basis for EPU Test Plan Elimination

EPU analysis determined that the existing drywell heat loads remain bounding for EPU operation. The drywell fan coil units have sufficient capacity to maintain the drywell at an average temperature of 135°F during normal operation and less than 150°F following a scram, and the CRD areas at less than 185°F following a scram for EPU operation. In addition, routine monitoring of drywell temperature is performed by Operations personnel. Based on analysis results and existing temperature monitoring, performance of this startup test is not required.

3.19 Test Number 79 – Penetration Cooling

UFSAR Test Description

The penetration cooling tests consist of measuring guard pipe temperatures surrounding selected main steam and RCIC piping penetrations in the auxiliary building. The RCIC piping penetration which will be monitored is the RCIC steam supply line, containment/auxiliary building penetration number 17. Measurements from a series of temperature sensors will be taken at rated reactor temperature in several test conditions. The measurements will be compared to the analytically permitted temperatures for both Level 1 and Level 2 criteria. The main steam line tunnel temperature will be monitored during power ascension testing.

Original Startup Test Results

While reactor thermal power was between 95% and 100%, penetration temperature data was recorded over a four (4) hour period. The guard pipe temperature adjacent to the selected containment penetrations was within the analytically predicted value corresponding to the maximum concrete temperature for both the Level 1 and Level 2 test criteria.

Basis for EPU Test Plan Elimination

Because reactor vessel pressure at 100% EPU power is the same as the reactor vessel pressure at 100% OLTP, main steam and RCIC steam supply temperatures will not be impacted. For this reason, the original startup test results remain valid for EPU conditions.

3.20 Reactor Pressure Vessel Level Control following Reactor Scram

Background

On January 30, 2004, Dresden Unit 3 experienced a turbine trip and automatic reactor scram as a result of low lube oil pressure while operating at 97% (113.5% OLTP) rated thermal power. Immediately following the scram, the position of the Feedwater Regulating Valves (FRVs) increased from 56% open to 63% open. The increase in the position, combined with the post-scram decreasing reactor pressure, caused an increase in total feedwater flow that led to the trip of the 'B' feedwater pump on low suction pressure. Additionally, subsequent FRV response to increasing reactor vessel level was not fast enough to prevent the level from reaching the Reactor Feedwater Pump (RFP) High Level trip setpoint and resulted in tripping of the 'A' and 'C' feedwater pumps. Reactor water level was subsequently restored to normal and the RFPs were restarted. All other system responses were as expected.

Subsequent investigations into the event determined that water had entered the High Pressure Coolant Injection (HPCI) piping rendering the system inoperable (HPCI uses a steam-driven pump to inject water into the reactor vessel). Dresden Unit 3 has a separate HPCI vessel nozzle located approximately 50 inches below the main steam line nozzles. An evaluation determined that Feedwater Level Control System (FWLCS) would not maintain the post-scram reactor water level below that which would prevent water from entering the HPCI turbine steam line. The root cause was attributed to a FWLCS that had low margin to accommodate changes to the post-scram vessel level response. The condition was not known because a model capable of predicting the dynamic interaction between the FWLCS and other factors was not available. This resulted in a failure to adequately evaluate or test the post-scram response of the FWLCS prior to implementing extended power uprate.

Applicability to GGNS

Unlike Dresden, there are no steam nozzles at an elevation lower than the main steam lines at GGNS. In addition, the GGNS has variable speed steam-driven feed pumps controlling reactor vessel instead of FRVs. Although this event is not directly applicable to GGNS, it is important that the FWLCS prevents the reactor vessel water level from reaching the Level 9 trip setpoint following a reactor scram to ensure continued vessel water level control by the normal method.

Basis for Exclusion of Post Scram Feedwater Response Testing

The GGNS EPU Power Ascension Test Plan currently does not contain any tests that result in a reactor scram. For this reason, the FWLCS response following a scram cannot be tested in conjunction with another test. As demonstrated by the generator

load reject that occurred on March 23, 2008 (see Section 3.10, Operational Experience since Startup), the current FWLCS maintains reactor water level below the Level 9 setpoint following a generator load reject from 100% CLTP with significant margin. There are no EPU modifications planned that would change the fundamental behavior of the FWLCS. An evaluation was performed that determined significant margin remained between the maximum reactor vessel water level following a reactor scram from EPU conditions and the bottom of the main steam lines. For these reasons, initiation of a reactor scram to test the FWLCS response is not warranted.

4.0 EPU POWER ASCENSION TEST PLAN

Aggregate impact of EPU plant modifications, setpoint adjustments and parameter changes will be demonstrated by a test program established for a Boiling Water Reactor (BWR) EPU in accordance with startup test specifications as described in PUSAR Section 2.12.1. The startup test specifications are based upon analyses and GE BWR experience with uprated plants to establish a standard set of tests for initial power ascension for EPU. These tests, which supplement the normal Technical Specification testing requirements, are summarized below:

- Testing will be performed in accordance with the Technical Specifications Surveillance Requirements on instrumentation that is re-calibrated for EPU conditions. Overlap between the Intermediate Range Monitors (IRMs) and Average Power Range Monitors (APRM) will be assured.

- Testing will be done to confirm the power level near the turbine first stage scram bypass setpoint.

- EPU power increases will be made in predetermined increments of ≤ 5% power starting at 90% CLTP Reactor Thermal Power (RTP) so that system parameters can be projected for EPU power before the CLTP RTP is exceeded. Operating data, including fuel thermal margin, will be taken and evaluated at each step. Routine measurements of reactor and system pressures, flows and vibration will be evaluated for each measurement point, prior to the next power increment. Radiation measurements will be made at selected power levels to ensure the protection of personnel.

- Control system tests will be performed for the reactor feedwater/reactor level controls and pressure controls. These operational tests will be made at the appropriate plant conditions for that test at each of the power increments, to show acceptable adjustments and operational capability.

- Steam dryer/separator performance will be confirmed within limits by determination of steam moisture content as required during power ascension testing.

- Vibration monitoring of main steam, feedwater and other balance of plant piping will be performed to permit a thorough assessment of the effect of EPU on this piping.

The same performance criteria will be used as in the original power ascension tests, except where they have been replaced by updated criteria since the initial test program. Because dome pressure and core flow have not changed and recirculation drive flow may increase slightly for EPU to achieve rated conditions, testing of system performance affected by these parameters is not necessary with the exception of the tests listed above.

The EPU testing program at GGNS, which is based on the specific testing required for the GGNS initial EPU power ascension, supplemented by normal Technical Specification testing, is confirmed to be consistent with the generic description provided in the CLTR.

EPU testing acceptance criteria is defined as follows:

- Level 1 Criteria – Criteria associated with plant safety. If a Level 1 test criterion is not met, the plant must be placed in a hold condition that is judged to be satisfactory and safe, based upon prior testing. Plant operating or test procedures, or Technical Specifications, may guide the decision on the direction to be taken. Tests consistent with this hold condition may be continued. Resolution of the problem must be immediately pursued by equipment adjustments or through engineering evaluation as appropriate. Following resolution, the applicable test portion must be repeated to verify that the Level 1 requirement is satisfied. A description of the problem must be included in the report documenting the successful test.

- Level 2 Criteria – Criteria associated with design performance. If a Level 2 test criterion is not met, plant operating or test plans would not necessarily be altered. The limits stated in this category are usually associated with expectations of system transient performance, whose characteristics can be improved by equipment adjustments. An evaluation would be initiated to investigate the performance parameters and equipment adjustments related to the criteria not met, as well as, the measurement and analytical methods, if appropriate. This evaluation must include alternative corrective actions and concluding recommendations.

4.1 EPU Test 1A – Chemical and Radiochemical (Original Test: SU-1)

EPU Test Description

Samples will be taken and measurements made at the EPU power levels to determine the chemical and radiochemical quality of reactor water, reactor feedwater and gaseous effluent.

Test Conditions

Chemical and radiochemical analyses will be conducted at 100% CLTP, 105% CLTP, 110% CLTP, and 100% EPU power levels.

Test Guidance

Testing will be performed using procedures 06-CH-1B21-O-0002, *Reactor Coolant Routine Chemistry*; 06-CH-1B21-W-0008, *Reactor Coolant Dose Equivalent Iodine*; the impacted final feedwater analyses governed by 08-S-03-10, *Chemistry Sampling Program*; 06-CH-1N62-M-0048, *Pretreatment Offgas Isotopic Analysis*; and 06-CH-1N64-M-0033, *Offgas Post-Treatment Exhaust Gaseous Isotopic*.

Acceptance Criteria

Level 1 Criteria:

- Chemical factors defined in the Operating License Manual (NPF-29) must be maintained within the limits specified.
- The activity of gaseous effluent conforms to current plant governing documents limitations.
- Water quality is known at all times and remains within the requirements of the utility chemistry program.

Level 2 Criteria: None

4.2 EPU Test 1B – Steam Dryer/Separator Performance

EPU Test Description

Samples will be taken and measurements made at the EPU test conditions to determine steam dryer/separator performance (i.e., moisture carryover). For this testing, main steam line moisture content is considered equivalent to the steam separator-dryer moisture carryover.

Test Conditions

Steam Dryer/Separator Performance will be determined at 100% CLTP; 105% CLTP; 110% CLTP; 100% EPU at the Maximum Extended Load Line Limit (MELLLA) Analysis boundary corner; and 100% EPU at the Increased Core Flow corner.

Test Guidance

Testing will be performed using procedure EN-CY-107, *Moisture Carryover Determination*.

Acceptance Criteria

Level 1 Criteria: None

Level 2 Criteria: MSL moisture content shall not be in excess of 0.1% by weight.

4.3 EPU Test 2 – Radiation Measurements (Original Test: SU-2)

EPU Test Description

At selected EPU power levels, gamma dose rate and, where appropriate, neutron dose rate measurements will be taken at specific limiting locations throughout the plant to assess the impact of the uprate on actual plant area dose rates. UFSAR radiation zones will be monitored for any required changes.

Test Conditions

Radiation monitoring will be conducted at 100% CLTP, 105% CLTP, 110% CLTP, and 100% EPU power levels.

Test Guidance

The locations to be monitored are provided on Table 9-3 along with the maximum radiation levels recorded during previous testing. The gamma dose rate locations are the areas monitored during the hydrogen water chemistry modification test. The neutron locations are selected areas monitored during the initial startup test. These locations were chosen to provide a representative sample of areas impacted by EPU. In addition, previous radiation survey information for these locations provides a baseline to allow for an evaluation of the EPU impact. The UFSAR radiation zones will also be monitored for any required changes. Testing will be performed using procedures EN-RP-106, *Radiological Survey Documentation*, and EN-RP-302, *Operation of Radiation Protection Instrumentation*.

Acceptance Criteria

Level 1 Criteria: The radiation doses of plant origin and the occupancy times of personnel in radiation zones shall be controlled consistent with the guidelines of The Standard for Protection Against Radiation outlined in 10 CFR Part 20.

Level 2 Criteria: None

4.4 EPU Test 10 – IRM Performance (Original Test: SU-10)

EPU Test Description

After the APRM calibration for EPU, IRM gains will be adjusted as necessary to assure the IRM overlap with the APRMs.

Test Conditions

During the first controlled shutdown following EPU implementation the IRM overlap with the APRMs will be verified.

Test Guidance

Monitoring and verification of proper overlap is performed in accordance with 03-1-01-3, *Plant Shutdown*.

Acceptance Criteria

Level 1 Criteria:

- Each IRM channel must be adjusted so that overlap with the respective APRM channel is consistent with the Operating License Manual (NPF-29).

- The IRMs must produce a scram at a setpoint consistent with the Operating License Manual (NPF-29).

Level 2 Criteria: None

4.5 EPU Test 12 – APRM Calibration (Original Test: SU-12)

EPU Test Description

Confirm the calibration of the APRMs is consistent with the rated thermal power, referenced to 100% EPU, as determined from the heat balance. Assure that the APRM flow-biased scram and rod block setpoints are consistent with EPU operation. Confirm all APRM trips and alarms prior to entering the EPU operating domain.

Test Conditions

APRM calibration will be completed prior to entering the EPU operating domain (consistent with Technical Specifications).

Test Guidance

Testing will be performed in accordance with existing plant procedures 06-IC-1C51-SA-0001, *Average Power Range Monitor Calibration,* and 06-RE-1C51-W-0001, *APRM Gain Adjustment.*

Acceptance Criteria

Level 1 Criteria:

- The APRM channels must be calibrated consistent with the Operating License Manual (NPF-29).

- Operating License Manual (NPF-29) limits on APRM scram and rod block setpoints shall not be exceeded.

Level 2 Criteria: None

4.6 EPU Test 19 – Core Performance (Original Test: SU-19)

EPU Test Description

Routine measurements of reactor power are taken near 90% and 100% CLTP to be used to increase to maximum EPU power. Core thermal power and core performance parameters are calculated using accepted methods to ensure current licensed and operational practice are maintained. Power increase in incremental steps of 5% or less of CLTP ensures a careful, monitored approach to maximum EPU power. Measured reactor parameters and calculated core performance parameters are utilized to project those values at the next power level step. Each step's actual values will be satisfactorily confirmed with the projected values for that step before advancing to the next step and the final confirmation at the maximum EPU power level.

Test Conditions

Power distribution limit verification will be conducted at 90% CLTP, 100% CLTP, 105% CLTP, 110% CLTP, and 100% EPU power levels.

Test Guidance

Once steady-state conditions are established at each power level step, measurements will be taken, core thermal cower and core performance parameters will be calculated and all values will be evaluated against projected values and operational limits before increasing power to the next step. Existing heat balance and core performance parameter calculation methods are used to maintain continuity with past and current accepted licensed and operational practice. Testing will be performed in accordance with existing plant procedure 06-RE-1J11-V-0001, *Power Distribution Limits Verification.*

Acceptance Criteria

Level 1 Criteria:

- All core performance parameters shall be within the limits specified in the Operating License Manual (NPF-29).
- Steady state reactor power shall be limited to maximum values of the lesser of either 100% EPU or the MELLLA Boundary as indicated on the Power-Flow Map.
- Core flow shall not exceed its maximum and minimum values depicted on the Power/Flow Map.

Level 2 Criteria: None

4.7 EPU Test 22 – Pressure Regulator (Original Test: SU-22)

EPU Test Description

This test will confirm the adequacy of the settings of the pressure control loop by inducing transients in the reactor pressure control system using the pressure regulators. In addition, data will be gathered to determine the incremental regulation and validate the first stage pressure scram bypass setpoint.

Test Conditions

Pressure setpoint steps will be performed at 90% CLTP, 100% CLTP, and 5% increments up to 100(+0/-5) % EPU power level. Data to determine the incremental regulation and validate the first stage pressure scram bypass setpoint will be obtained between minimum generator load and 100% EPU power as required.

Test Guidance

The pressure control system transient will be introduced by lowering the pressure setpoint up to 6 psi then increasing the setpoint by the same amount once conditions have stabilized. It is desirable to accomplish the setpoint change in less than 1 second. The response of the system will be measured and evaluated for each change.

Steady state values of total steam flow and controlling pressure regulator output will be collected in increments of less than 3% during ascension to maximum EPU power. This data will be plotted on a linear graph that will be used to determine compliance with the incremental regulation criteria.

Data will be collected on the turbine first stage pressure to thermal power relationship over a band bounding all the setpoints that are based on this pressure. This data will be used to validate the setpoint subsequent to the EPU power ascension.

This test will be performed in accordance with a Special Test Instruction (STI) developed to provide the specific testing methodology.

Acceptance Criteria

Level 1 Criteria: The transient response of any pressure control system related variable to any test input must not diverge.

Level 2 Criteria:

- Pressure control system related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be ≤ 0.25.
- The pressure response time from initiation of pressure setpoint input change to the turbine inlet pressure peak shall be ≤ 10 seconds.
- Pressure control system deadband, delay, etc. shall be small enough that steady-state limit cycles, if any, shall produce turbine steam flow variations no larger than ± 0.5% of rated steam flow.
- For all pressure regulator transients, the peak neutron flux and/or peak vessel pressure shall remain below the scram settings by 7.5% and 10 psi, respectively.
- The variation in incremental regulation shall meet the specified UFSAR criteria.

4.8 EPU Test 23 – Feedwater System (Original Tests: SU-23B and SU-23D)

EPU Test Description

This test will verify that the feedwater control system has been adjusted to provide acceptable reactor water level control over EPU operating conditions, confirm the feedwater flow calibration, and validate that the maximum feedwater runout capability is compatible with the licensing assumption for the EPU conditions.

Test Conditions

Level / flow setpoint steps will be performed at 90% CLTP, 100% CLTP, and 5% increments up to 100(+0/-5) % EPU power level. (Note: One of the EPU manual flow step change test conditions may be skipped at the test director's direction provided that acceptable performance is demonstrated at the lower power test condition and the test condition being skipped is not the final EPU test condition.) The feedwater flow calibration and maximum feedwater runout data will be obtained at 90% CLTP, 100% CLTP, 105% CLTP, 110% CLTP, and 100% EPU power levels.

Test Guidance

The feedwater control system response to reactor normal operating water level setpoint changes are evaluated in the indicated control mode (i.e., three element, single element). At each test condition, level setpoint change testing is performed by first making an up setpoint value change, followed by a down setpoint value change of the same value, after conditions stabilize, in accordance with the following setpoint change sequence:

- +2 inches
- -2 inches
- +3 inches
- -3 inches
- +4(±1) inches
- -4(±1) inches

The 2 and 3-inch level setpoint steps are informational and recommended to demonstrate the level control response prior to performing the formal plus and minus level setpoint changes of 4 ± 1 inches. The results from the informational level setpoint steps are utilized to anticipate the responses (i.e., power increases, level alarms) to the formal demonstration test steps. The tolerance of the formal level step permits adjustment to take into consideration the limit cycles of the control mode being tested. If the limit cycles are small enough to permit the formal steps to be at the lower end of the tolerance (i.e., 3 inches), then the informational 3-inch steps need not be performed.

The Feedwater Control System operates in the three-element control mode during normal full power operations. The single-element control mode is used only temporarily when necessary during normal full power operations until the three-element control mode can be restored. The feedwater control system in three-element control mode should be adjusted, not only for stable operational transient level control (i.e., decay ratio), but also for stable steady-state level control (i.e., minimize reactor water limit cycles). In single-element control mode, the system adjustments must achieve the operational transient level control criteria; but, for steady-state level control, single element control is only used for temporary backup situations except during portions of the feedwater controller testing where the test point indicates that single element feedwater control mode is specified for the test.

For tests calling for manual flow step changes, at each test condition the feedwater control system is placed in a manual/auto configuration (i.e., one Reactor Feed Pump (RFP) is placed in manual and the other in automatic controlling water level). Preferably, the flow step changes are made by inserting the step demand change into the feedwater RFP controller in manual or alternately by changing the setpoint of that controller in accordance with the following setpoint change sequence expressed in percent of rated EPU feedwater flow. After completion of testing on one controller, the manual/auto configuration is switched and the sequence is repeated on the other controller.

- Increase 5%
- Decrease 5%
- Increase 10%
- Decrease 10%

The 5% flow step changes are informational and recommended to demonstrate the RFP response prior to performing the formal test flow step changes (i.e., ±10%). The results from the smaller informational flow step are utilized to anticipate the responses to the formal demonstration test, so that effects on the reactor may be anticipated (i.e., level changes, power increases).

Feedwater flow data from the leading edge flow meter (LEFM) and the feedwater venturi instrumentation will be compared to validate the feedwater venturi accuracy at EPU conditions.

Feedwater system performance data is gathered to determine the RFP speed corresponding to the maximum feedwater runout flows used as the transient analyses assumptions. System control adjustments are set to prevent the RFPs from exceeding their maximum allowable flows, and still allow the desirable performance.

This test will be performed in accordance with an STI developed to provide the specific testing methodology.

<u>Acceptance Criteria</u>

Level 1 Criteria:

- The transient response of any level control system related variable to any test input must not diverge.

- The maximum feedwater runout capacity, as determined from measured data in comparison to expected values and adjusted to the specified pressure, shall not exceed the value assumed in the demand analysis for the maximum cycle-specific feedwater controller failure.

Level 2 Criteria:

- Level control system related variables may contain oscillatory modes of response. In these cases, the decay ratio for each controlled mode of response must be ≤ 0.25.

- The open loop dynamic response of each RFP to small (<10% of rated feedwater pump flow) step disturbances shall meet the specified UFSAR criteria.

- Feedwater flow capability should be at least 5% greater than the normal steady state operating feedwater flow rate at full EPU power.

4.9 EPU Test 24 – Turbine Valve Surveillance (Original Test: SU-24)

EPU Test Description

Utilizing the original Standard Technical Specification (STS) methodology, initial tests are performed at two points below and near the power level at which each valve's surveillance has been performed in pre-EPU uprate tests. A maximum power test condition will be determined by projecting the initial tests' scram/trip setpoint margins to the highest power level where all the margins remain acceptable. A final test is performed at this maximum power test condition to confirm acceptable test performance. For all tests, the proximity to vessel pressure, neutron flux and heat flux scram, and main steam line flow isolation trip, will be closely monitored.

Test Conditions

The turbine valve surveillance will be conducted at the following power levels:

- Between 40%-65% of EPU
- Between 65%-80% of EPU
- At or near selected maximum power level based on evaluation of previous test data

Test Guidance

Turbine valve testing will be performed in accordance with 06-OP-1N32-V-0001, *Turbine Stop and Control Valve Operability*.

Acceptance Criteria

Level 1 Criteria: None

Level 2 Criteria:

- Peak neutron flux must be at least 7.5% below the scram trip setting.
- Peak vessel pressure must remain at least 10 psi below the high pressure scram setting.
- Peak heat flux must be at least 5.0% below its scram setting.
- Peak steam flow in each line must remain 10% below the high flow isolation trip setting.

4.10 EPU Test 100 – Main Steam and Feedwater Piping Vibration (Original Test: SU-33)

EPU Test Description

During the EPU power ascension, designated main steam, feedwater and balance-of-plant (BOP) piping points (i.e., location and direction) will be monitored for vibration. Vibration monitoring points will be designated based on EPU piping vibration analysis and engineering judgment as detailed in Attachment 10 of this LAR. Monitoring points may be coincidental with those in the initial startup piping vibration test or be selected as those points with the highest predicted vibration. Alternately, vibration monitoring points can be coincidental with exposed piping attachments provided that acceptance criteria are established for those points based on piping system vibration analysis. Vibration measurements taken above CLTP will permit a thorough assessment of the effect of the EPU in comparison to any previous piping vibration analysis or evaluation.

Test Conditions

Baseline data will be taken at 50%, 75% and 100% CLTP power. During the ascent to EPU conditions from 100% CLTP, data will be evaluated every 2.5% increase.

Test Guidance

Hold points (96-hour minimum) will be established every 5% above CLTP for Onsite Safety Review Committee (OSRC) and NRC reviews. In the event that measured vibrations at a given power level exceed the acceptance criteria, an evaluation will be performed to disposition the test deficiency. If appropriate, the power level will be reduced to a level where vibration amplitudes were previously shown to be acceptable until the deficiency can be corrected.

This test will be performed in accordance with an STI developed to provide the specific testing methodology.

Acceptance Criteria

Level 1 and Level 2 Criteria are pre-established by evaluating the EPU piping vibration analyses and acceptable margins to determine the allowable vibration levels at the designated points (i.e., location and direction.).

4.11 EPU Test 101 – Plant Parameter Monitoring and Evaluation (Original Tests: SU-74/SU-75)

EPU Test Description

Routine measurements of the power-dependent parameters from systems and components affected by the EPU are taken at the EPU power levels. Power-dependent parameters that are calculated will be calculated using accepted methods to ensure current licensed and operational practices are maintained. Measured and calculated power-dependent parameters are utilized to project those values at the next power level step prior to increasing to the next EPU test condition. Each step's projected values will be evaluated to have satisfactorily confirmed the actual values before advancing to the next step and the final increase to maximum EPU power. Data required to evaluate the

offgas system (Original Startup Test SU-74) and affected cooling water systems (Original Startup Test SU-75) will also be obtained by this test.

Test Conditions

Power-dependent data will be obtained at 90% and 100% of CLTP that will be used to increase to maximum EPU power. Power increases in incremental steps of 2.5% of CLTP will ensure a careful, monitored approach to maximum EPU power.

Test Guidance

Once steady-state conditions are established at each power level step, measurements will be taken and all values will be evaluated against projected values and operational limits before increasing power the next step. Existing parameter calculation methods are used to maintain continuity with past and current accepted licensing and operational practices.

This test will be performed in accordance with an STI developed to provide the specific testing methodology.

Acceptance Criteria

Level 1: All power-dependent parameters shall be within the limits specified in the Operating License Manual (NPF-29), if such limits apply to any parameters.

Level 2: All power-dependent parameters should be within system and equipment design limits.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-1	**CHEMICAL AND RADIOCHEMICAL** • To secure information on the chemistry and radiochemistry of the reactor coolant. • To determine that the sampling equipment, procedures, and analytic techniques are adequate to demonstrate that the chemistry of all parts of the entire reactor system meets specifications and process requirements.	Level 1 • Chemical factors defined in the Technical Specifications and Fuel Warranty must be maintained within the limits specified. • Activities of gaseous and liquid effluents must conform to license limitations • Water quality must be known at all times and must remain within the guidelines of the Water Quality Specifications.	94%	Original test performed greater than or equal to 80% power. Test will be included in the EPU power ascension test plan (See Section 4.1 for EPU test description).
SU-2	**RADIATION MEASUREMENT** • To determine the background radiation levels in the plant environs prior to operation for base data on activity buildup. • To monitor radiation at selected power levels to assure the protection of personnel during plant operation.	Level 1 – The radiation doses of plant origin and the occupancy times of personnel in radiation zones shall be controlled consistent with the guidelines of the Standards for Protection Against Radiation outlined in 10 CFR 20.	100%	Original test performed greater than or equal to 80% power. Test will be included in the EPU power ascension test plan (See Section 4.3 for EPU test description).

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-3	**FUEL LOADING** To load fuel safely and efficiently to the full core size.	Level 1 – The partially loaded core must be subcritical by at least 0.38 Δk/k with the analytically determined strongest rod fully withdrawn.	N/A	Original test invalidated due to EPU fuel load. Test will be performed in accordance with existing plant procedures 17-S-02-300, *Fuel and Core Component Movement Control* and 17-S-02-108, *Core Loading Verification*.
SU-4	**FULL CORE SHUTDOWN MARGIN** The purpose of this test is to demonstrate that the reactor will be subcritical throughout the first fuel cycle with any single control rod fully withdrawn.	Level 1 – The shutdown margin of the fully loaded, cold (68 F or 20 C), xenon-free core occurring at the most reactive time during the cycle must be at least 0.38 percent Δk/k with the analytically strongest rod (or its reactivity equivalent) withdrawn. Level 2 – Criticality should occur within ± 1.0 percent Δk/k of the predicted critical.	N/A	Original test invalidated due to EPU fuel load. Test will be performed in accordance with existing plant procedures 06-RE-SB13-V-0401, *Shutdown Margin Demonstration* and 17-S-02-400, *Control Rod Sequences and Movement Control*.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-5	**CONTROL ROD DRIVE (CRD) SYSTEM** • To demonstrate that the CRD system operates properly over the full range of primary coolant temperatures and pressures from ambient to operating. • To determine the initial operating characteristics of the entire CRD system.	Level 1 • Each CRD must have a normal withdraw speed less that or equal to 3.6 inches per second. • The maximum scram times of individual CRDs shall comply with UFSAR criteria. Level 2 • In the continuous gang rod mode, the rods shall always move together so that all rods are within two notches of all other rods in the gang. • Each CRD must have a normal insert or withdrawal speed between 2.4 and 3.6 inches per second. • The control rod drive friction tests must meet UFSAR criteria. • The CRD's total cooling water flow rate shall be between 0.28 and 0.34 gpm times the total number of drives.	100%	Original scram time testing performed in conjunction with Generator Load Reject test at 100% power. In addition, refueling outages have the potential to impact CRD performance. Although CLTR, ELTR1, and SRP 14.2 do not discuss CRD system testing as a recommended EPU test, the following plant procedures will provide adequate system verification following the EPU refueling outage: • 06-RE-SC11-V-0402, *Control Rod Scram Testing* • 04-S-03-C11-5, *Control Rod Stroke Time Testing*

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-6	**SOURCE RANGE MONITOR (SRM) PERFORMANCE** To demonstrate that the operational sources, SRM instrumentation, and rod withdrawal sequences provide adequate information to achieve criticality and increase power in a safe and efficient manner.	Level 1 • There must be a neutron signal count-to-noise count ratio of at least 2 to 1 on the required operable SRMs. • There must be a minimum count rate of 0.7 counts/second on the required operable SRMs. • The IRMs must be on scale before the SRMs exceed the rod block set point.	N/A	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.
SU-8	**ROD SEQUENCE EXCHANGE** To perform a representative sequence exchange of control rod patterns at a significant power level.	Level 1 – Completion of the exchange of one rod pattern for the complementary pattern with continual satisfaction of all licensed core limits constitutes satisfaction of the requirements of this procedure. Level 2 – All nodal powers must remain below their fuel conditioning thermal limits during this test.	N/A This test was determined to be non-essential and was not performed at GGNS	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.
SU-10	**INTERMEDIATE RANGE MONITOR (IRM) PERFORMANCE** To adjust the IRM system to obtain an optimum overlap with the SRM and APRM systems.	Level 1- Each IRM channel must be adjusted so that the overlap with the SRMs and APRMs is assured. The IRMs must produce a scram at 96 percent of full scale.	~5%	Original test invalidated due to APRM rescaling. Test will be included in the EPU power ascension test plan (See Section 4.4 for EPU test description).

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-11	**LOCAL POWER RANGE MONITOR (LPRM) CALIBRATION** To calibrate the LPRM system.	Level 2 – Each LPRM reading will be within 10 percent of its calculated value	97%	Original test performed greater than or equal to 80% power. Test will be performed in accordance with existing plant procedures 06-RE-1C51-O-0001, *Local Power Range Monitor Calibration*.
SU-12	**APRM CALIBRATION** To calibrate the APRM system.	Level 1 • The APRM channels must be calibrated to read equal to or greater than the actual core thermal power. • Technical Specification and Fuel Warranty Limits on APRM scram and rod block shall not be exceeded. • In the startup mode, all APRM channels must produce a scram at less than or equal to 15 percent of rated thermal power.	95%	Original test performed greater than or equal to 80% power. Test will be included in the EPU power ascension test plan (See Section 4.5 for EPU test description).
SU-13	**NUCLEAR STEAM SUPPLY SYSTEM (NSSS) PROCESS COMPUTER** To verify the performance of the NSSS process computer under plant operating conditions.	Level 2 – The process computer programs will be considered operational when the UFSAR acceptance criteria are met.	96%	Although CLTR, ELTR1, and SRP 14.2 do not discuss process computer testing as a recommended EPU test, it will be tested as part of PRNM post-modification testing.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-14	**REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM** • To verify the proper operation of the RCIC system over its expected operating pressure and flow ranges. • To demonstrate reliability in automatic starting from cold standby when the reactor is at power conditions.	Level 1 • The average pump discharge flow must be ≥100% rated value after 30 seconds have elapsed from automatic initiation at any reactor pressure between 150 psig and rated. • The RCIC turbine shall not trip or isolate during auto or manual start tests. Level 2 • The first and subsequent speed peaks associated with the transient quick start shall not exceed the rated RCIC turbine speed. • The speed and flow control loops shall be adjusted so that the decay ratio of any RCIC system related variable is not greater than 0.25. • The turbine gland seal air compressor shall be capable of preventing steam leakage. • The differential pressure switch for the RCIC steam supply line high flow isolation trip shall be calibrated to actuate at the value specified in the plant Technical Specifications.	54%	Original test performed at less than 80% power. Because EPU does not cause a RPV pressure increase, this test is not invalidated as a result of EPU. For these reasons, this test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-16A	**SELECTED PROCESS TEMPERATURES** • To assure that the measured bottom head drain temperature corresponds to bottom head coolant temperature during normal operations. • To identify any reactor operating modes that cause temperature stratification. • To determine the proper setting of the low-flow control limiter for the recirculation pumps to avoid coolant temperature stratification in the reactor pressure vessel bottom head region. • To familiarize plant personnel with temperature differential limitations of the reactor system.	Level 1 • The reactor recirculation pumps shall not be started nor flow increased unless the coolant temperatures between the steam dome and bottom head drain are within 100°F. • The recirculation pump in an idle loop must not be started unless the loop suction temperature is within 50°F of the active loop suction temperature, or the steam dome temperature if one pump is idle.	100%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.1.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-16B	**WATER LEVEL REFERENCE LEG TEMPERATURE** To measure the reference leg temperature and recalibrate the instruments if the measured temperature is different than the value assumed during the initial calibration.	Level 2 • The indicator readings on the Narrow Range Level System should agree within ± 1.5 inches of the average reading. • The Wide Range Level System indicators should agree within ± 6 inches of the average reading.	96%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.2.
SU-17	**SYSTEM EXPANSION** • To confirm that the pipe suspension system is working as designed. • To confirm that the pipe is free of obstructions that could constrain free pipe movement.	Level 1 – The Level 1 movement ranges provided in UFSAR Table I and the Startup Test Procedure are intended to set bounds on thermal movement which, if exceeded, requires that the test be placed on hold. Level 2 – Level 2 limits on piping displacements are provided in UFSAR Table I.	96%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.3.
SU-18	**CORE POWER DISTRIBUTION** To determine the reproducibility of the TIP system readings.	Level 2 – The total TIP uncertainty (including random noise and geometrical uncertainties), obtained by averaging the uncertainties for all data sets, shall be less than 6.0 percent.	100%	Original test performed greater than or equal to 80% power. Test will be performed in accordance with existing plant procedure EN-RE-209, *TIP Symmetry Check*.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-19	**CORE PERFORMANCE** • To evaluate the core thermal power and flow. • To evaluate whether the following core performance parameters are within limits: – Maximum Linear Heat Generation Rate (MLHGR). – Minimum Critical Power Ratio (MCPR). – Maximum Average Planar Linear Heat Generation Rate (MAPLHGR).	Level 1 • Steady-state reactor power shall be limited to the rated MWt and values on or below the 105% rod line. • The MLHGR of any rod during steady-state conditions shall not exceed the limit specified by the plant Technical Specifications (TS). • The MCPR during steady-state conditions shall not exceed the limit specified by the TS. • The MAPLHGR during steady-state conditions shall not exceed the limit specified by TS. • Core flow shall not exceed its rated value.	96%	Original test performed greater than or equal to 80% power. Test will be included in the EPU power ascension test plan (See Section 4.6 for EPU test description).
SU-20	**STEAM PRODUCTION STARTUP TEST** To demonstrate that the nuclear steam supply system is providing sufficient steam to satisfy all appropriate warranties as defined in the contract.	Level 1 ▪ The NSSS parameters shall be within the appropriate license restrictions. ▪ The NSSS will be capable of supplying steam in an amount and quality corresponding to the Rated Steam Output Curve in the NSSS technical description. ▪ Thermodynamic parameters are consistent with the ASME Steam Tables.	96%	Original test performed greater than or equal to 80% power. This test validated NSSS supplier production requirements and did not involve any TS or UFSAR commitments. EPU contractual guarantees will be verified outside the EPU power ascension test program.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-21	**CORE POWER – VOID MODE** To measure the stability of the core power-void dynamic response and to demonstrate that its behavior is within specified limits.	Level 1 – The transient response of any system-related variable to any test input must not diverge.	77%	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.
SU-22	**PRESSURE REGULATOR** ▪ To determine the optimum settings for the initial pressure control (IPC) loop by analysis of the transients induced in the reactor pressure control system by means of the pressure controller. ▪ To demonstrate the capability of the IPC to maintain stable pressure control for various IPC single failure situations. ▪ To demonstrate smooth pressure control transition between the control valves and bypass valves when reactor steam generation exceeds steam used by the turbine.	Level 1 – The decay ratio must be no greater than 1.0 for each pressure control system related process variable that exhibits oscillatory response to pressure controller changes. Level 2 ▪ The decay ratio for each oscillatory modes of response must be less than or equal to 0.25. ▪ Steady-state limit cycles, if any, shall produce turbine steam flow variations no larger than ±0.5 percent of rated flow. ▪ For all pressure regulator transients, the peak neutron flux and/or peak vessel pressure shall remain below the scram settings by 7.5% and 10 psi, respectively. ▪ The variation in incremental regulation shall meet the specified UFSAR criteria.	97%	Original test performed greater than or equal to 80% power. Test will be included in the EPU power ascension test plan (See Section 4.7 for EPU test description).

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-23A	**FEEDWATER PUMP TRIP** To demonstrate the capability of the automatic core flow runback feature to prevent low water level scram following the trip of one feedwater pump.	Level 2 – A scram must not occur from low water level following a trip of one of the operating feedwater pumps. There should be greater than 3-inch water level margin to scram for a feedwater pump trip initiated at 100% power conditions.	95%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.4.
SU-23B	**WATER LEVEL SET POINT, MANUAL FEEDWATER FLOW CHANGES** To verify that the feedwater system has been adjusted to provide acceptable reactor water level control.	Level 1 – The transient response of any level control system-related variable to any test input must not diverge. Level 2 ▪ The decay ratio for each oscillatory modes of response must be less than or equal to 0.25. ▪ The open loop dynamic flow response of each feedwater actuator to small step disturbances shall meet the UFSAR criteria.	96%	Original test performed greater than or equal to 80% power. Test will be included in the EPU power ascension test plan (See Section 4.8 for EPU test description).

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-23C	**LOSS OF FEEDWATER HEATING** To demonstrate adequate response to a feedwater temperature loss.	Level 1 ▪ The maximum feedwater temperature decrease due to a single failure case must be ≤100°F. The resultant MCPR must be greater than the fuel thermal safety limit. ▪ The increase in simulated heat flux cannot exceed the predicted Level 2 value by more than 2 percent. Level 2 – The increase in simulated heat flux cannot exceed the predicted value referenced to the actual feedwater temperature change and power level.	90%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.5.
SU-23D	**MAXIMUM FEEDWATER RUNOUT CAPABILITY** To determine that the maximum feedwater runout capability is compatible with the safety analysis assumptions.	Level 1 – Maximum speed attained shall not exceed the speeds which will give the flows provided in the UFSAR with the normal complement of pumps operating. Level 2 – The maximum speed must be greater than the calculated speeds required to supply the values provided in the UFSAR.	97%	Original test performed greater than or equal to 80% power. Test will be included in the EPU power ascension test plan (See Section 4.8 for EPU test description).

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-24	**TURBINE VALVE SURVEILLANCE** To demonstrate the acceptable procedures and maximum power levels for surveillance testing of the main turbine control, stop, and bypass valves without producing a reactor scram.	Level 2 ▪ Peak neutron flux must be at least 7.5% below the scram trip setting. Peak vessel pressure must remain at least 10 psi below the high pressure scram setting. Peak heat flux must remain at least 5.0 % below its scram trip point. ▪ Peak steam flow at each line must remain 10% below the high flow isolation trip setting.	92%	Original test performed greater than or equal to 80% power. Test will be included in the EPU power ascension test plan (See Section 4.9 for EPU test description).
SU-25A	**MSIV FUNCTIONAL TESTS** ▪ To functionally check the MSIVs for proper operation at selected power levels. ▪ To determine isolation valve closure times. ▪ To determine maximum power at which full closures of a single valve can be performed without a scram.	Level 1 – The MSIV stroke time (t_s) for any individual valve shall be 3.0 seconds ≤ t_s ≤ 5.0 seconds. Total effective closure (including delay time) for any individual MSIV shall be ≤ 5.5 seconds. Level 2 – During full closure of individual valves, peak vessel pressure must be 10 psi below scram, peak neutron flux must be 7.5 percent below scram, and steam flow in individual lines must be 10 percent below the isolation trip settings. The peak heat flux must be 5 percent less than its trip point.	84%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.6.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-25B	**FULL REACTOR ISOLATION** To determine the reactor transient behavior that results from the simultaneous full closure of all MSIVs.	Level 1 ▪ The positive change in vessel dome pressure occurring within 30 seconds after closure of all MSIV valves must not exceed the Level 2 criteria by more than 25 psi. The positive change in simulated heat flux shall not exceed the Level 2 criteria by more than 2 percent of the rated value. ▪ Feedwater control system settings must prevent flooding the steam lines. Level 2 ▪ The RCIC system shall adequately take over water level protection. The relief valves must reclose properly following the pressure transient. ▪ The increase in dome pressure and heat flux shall be less than the upper limits defined in the Transient Safety Analysis Design Report ▪ Initial action of the RCIC and HPCS shall be automatic when water Level 2 is reached, and system performance shall be within specifications. ▪ Recirculation runback shall occur. Recirculation pump trip shall be initiated when Level 2 is reached.	75% (NRC Letter of 5/13/85 approved use of inadvertent full MSIV isolation at 75% power to satisfy the 95%-100% startup test)	Original test results extrapolated to greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.7.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-25C	**MAIN STEAM LINE FLOW VENTURI CALIBRATION** To calibrate the main steam flow venturis at selected power levels over the entire core flow range.	Level 2 ▪ The accuracy of the flow venturis relative to the calibrated feedwater flow shall be at least ±5 % of rated flow at flow rates between 20 and 120 % of rated steam line flow. The repeatability/noise shall be within ±15 % of rated flow. ▪ The flow venturi dp shall be equal to or greater than 79.3 psi at rated steam flow.	99%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.8.
SU-26	**RELIEF VALVES** ▪ To verify that the relief valves function properly (can be open and closed manually). ▪ To verify that the relief valves reseat properly after operation. ▪ To verify that there are no major blockages in the relief valve discharge piping. ▪ To confirm proper overall functioning of the low-low set pressure relief logic.	Level 1 ▪ There should be a positive indication of steam discharge during the manual actuation of each valve. ▪ The low-low set pressure relief logic shall function to preclude subsequent simultaneous SRV actuations following the initial SRV actuation due to original pressurization transient. Level 2 – In accordance with UFSAR criteria.	100%	Original test performed greater than or equal to 80% power in conjunction with MSIV and Generator Load Reject testing. Justification for eliminating this test from the EPU Test Program is provided in Section 3.9.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-27	**TURBINE TRIP AND GENERATOR LOAD REJECTION** To demonstrate the response of the reactor and its control systems to protective trips in the turbine and the generator.	Level 1 ▪ There should be a delay of less than 0.1 second following the beginning of control or stop valve closure before the beginning of bypass valve opening with the bypass valves ≥80% of capacity within 0.3 seconds. ▪ Feedwater system settings must prevent flooding of the steam line following these transients. ▪ The two pump drive flow coastdown transient during the first 3 seconds must be equal to or faster than that specified in Test 30. ▪ The positive change in vessel dome pressure occurring within 30 seconds must be equal to or faster than that specified in Test 30. ▪ The positive change in simulated heat flux shall not exceed the Level 2 criteria by more than 2 percent of rated value. Level 2 – In accordance with UFSAR criteria.	100%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.10.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-28	**SHUTDOWN FROM OUTSIDE THE MAIN CONTROL ROOM** To demonstrate that the reactor can be brought from a normal initial steady-state power level to the point where cooldown is initiated and under control with reactor vessel pressure and water level controlled from outside the control room.	During a simulated control room evacuation, the reactor must be brought to the point where cooldown is initiated and under control, and the reactor vessel pressure and water level are controlled using equipment and controls outside the control room.	27%	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.
SU-29A	**RECIRCULATION VALVE POSITION CONTROL** To demonstrate the capability of the recirculation flow control system when in the valve position mode.	Level 1 – The transient response of any recirculation system-related variables to any test input must not diverge. Level 2 ▪ The decay ratio for each controlled mode of response must be less than or equal to 0.25. ▪ While operating on the high speed source, gains and limiters shall be set to obtain the responses provided in the UFSAR.	96%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.11.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-29B	**RECIRCULATION FLOW LOOP CONTROL** ▪ To demonstrate the core flow system's control capability over the entire flow control range, including both core flow neutron flux and load following modes of operation. ▪ To determine that all electrical compensators and controllers are set for desired system performance and stability.	Level 1 – The transient response of any recirculation system-related variable to any test input must not diverge. Level 2 – In accordance with UFSAR criteria.	99%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.12.
SU-30A	**REACTOR RECIRCULATION SYSTEM ONE PUMP TRIP** ▪ To obtain recirculation system performance data during the pump trip, flow coastdown, and pump restart. ▪ To verify that the feedwater control system can satisfactorily control water level without a resulting turbine trip/scram.	Level 2 ▪ The reactor water level margin to avoid a higher level trip shall be ≥3.0 inches. ▪ The simulated heat flux margin to avoid a scram shall be ≥5.0 percent during trip recovery. ▪ The APRM margin to avoid a scram shall be ≥7.5 percent during trip recovery. ▪ The time from zero pump speed to full pump speed shall be greater than 3 seconds.	100%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.13.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-30B	**RPT TRIP OF TWO PUMPS** To record and verify acceptable performance of the recirculation two-pump circuit trip system.	Level 1 – The two-pump drive flow coastdown transient during the first 3 seconds must be bounded by the curves specified on UFSAR Figure 14.2-6, adjusted for transmitter time delay and time constant.	98%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.14.
SU-30C	**REACTOR RECIRCULATION SYSTEM PERFORMANCE** To record recirculation system parameters during the power test program.	Level 2 ▪ The core flow shortfall shall not exceed 5 percent at rated power. ▪ The drive flow shortfall shall not exceed 5 percent at rated power	99%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.15.
SU-30D	**REACTOR RECIRCULATION PUMP RUNBACK** To verify the adequacy of the recirculation runback to mitigate a scram on loss of one feedwater pump.	None	57%	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-30E	**REACTOR RECIRCULATION SYSTEM CAVITATION** To verify that no recirculation system cavitation will occur in the operable region of the power-flow map.	Level 2 - Runback logic settings must be adequate to prevent operation in areas of potential cavitation.	58%	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.
SU-31	**LOSS OF TURBINE GENERATOR AND OFFSITE POWER** To determine the electrical equipment and reactor transient performance during the loss of auxiliary power.	Level 1 ▪ Reactor protection system actions shall prevent violation of fuel thermal limits. ▪ All safety systems must function properly without manual assistance; and the reactor water level shall be kept above the initiation level of LPCS, LPCI, and ADS. Level 2 – Proper instrumentation display to the reactor operator shall be demonstrated.	29%	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-33	**DRYWELL PIPING VIBRATION** ▪ To verify that the main steam, recirculation, and RCIC steam piping vibration is within acceptable limits. ▪ To verify that pipe stresses are within code limits during operating transient loads.	Level 1 and Level 2 vibration limits provided in UFSAR for both transient and steady-state vibration conditions.	100%	Original test performed greater than or equal to 80% power. Steady-state vibration testing will be performed for piping impacted by EPU. Vibration measurements for transient conditions and piping not impacted by EPU are not included in the EPU testing scope. Section 4.10 and Attachment 10 of this LAR describes the EPU vibration scope. Justification for eliminating a portion of the original vibration testing scope is provided in Section 3.16.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-34	**VIBRATION MEASUREMENTS** To obtain vibration measurements on the reactor internal components and to demonstrate the mechanical integrity of the system to flow-induced vibration. Testing is in response to NRC Regulatory Guide 1.20 which describes a vibration measurement program and an inspection program.	Level 1 – The peak stress intensity may exceed 10,000 psi (single amplitude) when the component is deformed in a manner corresponding to one of its normal or natural modes, but the fatigue usage factor must not exceed 1.0. Level 2 – The peak stress intensity shall not exceed 10,000 psi (single amplitude) when the component is deformed in a manner corresponding to one of its normal or natural modes. This is the low stress limit which is suitable for sustained vibration in the reactor environment for the design life of the reactor components.	99%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.17.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-35	**RECIRCULATION SYSTEM FLOW CALIBRATION** To perform complete calibration of the installed recirculation system flow instrumentation.	Level 2 ▪ Jet pump flow instrumentation shall be adjusted such that the jet pump total flow recorder will provide a correct core flow indication at rated conditions. ▪ The ARPM flow-bias instrumentation shall be adjusted to function properly at rated conditions. ▪ The flow control system shall be adjusted to limit the maximum core flow to 102.5 percent of rated by limiting the flow control valve opening position.	Cannot locate SU test results	Original test performed greater than or equal to 80% power. Test will be performed in accordance with existing plant procedure 17-S-02-4, *Post Refueling Outage Data Collection and Analysis.*
SU-36	**ISOLATION REACTOR STABILITY** ▪ To demonstrate that an isolated reactor has satisfactory dynamic stability at very low power and medium-to-high-pressure conditions. ▪ To determine any higher pressure operating restrictions due to isolated reactor instability.	Level 2 ▪ The transient response of any system-related variable to any test input must not diverge. ▪ For expected small- and medium-sized inputs or disturbances, the reactor must not diverge beyond a scram trip setting in less than 3 minutes. ▪ Any steady pressure limit cycle shall not exceed ±100 psi. For those limit cycles whose period is < 10 seconds, the allowed maximum is ±20 psi.	N/A	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-70	**REACTOR WATER CLEANUP (RWCU) SYSTEM** To demonstrate specific aspects of the mechanical ability of the RWCU system. (This test, performed at rated reactor pressure and temperature, is actually the completion of the preoperational testing that could not be done without nuclear heating.)	Level 2 ▪ The temperature at the tube side outlet of the nonregenerative heat exchangers shall not exceed 130°F in the Blowdown mode and shall not exceed 120°F in the Normal mode. ▪ The pump available NPSH will be 13 feet or greater during the Hot Shutdown with loss of RPV recirculation pumps mode. ▪ The cooling water supplied to the nonregenerative heat exchangers shall be within the flow and outlet temperature limits indicated in the process diagrams and system specification. ▪ During two-pump operation at rated core flow, the bottom head temperature should be within 30°F of the recirculation loop temperatures. ▪ Recalibrate bottom head flow indicator against RWCU flow indicator if deviation is greater than 10 gpm. ▪ Pump vibration shall be less than or equal to the limits given by the Hydraulic Institute Standards.	74%	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-71	**RESIDUAL HEAT REMOVAL (RHR) SYSTEM** ▪ To demonstrate the ability of the RHR system to remove the residual and decay heat from the nuclear system so that the refueling and nuclear servicing can be performed. ▪ To demonstrate the ability of the RHR system to condense steam while the reactor is isolated from the main condenser.	Level 1 – The transient response of any system-related variable to any test input must not diverge. Level 2 – The RHR system shall be capable of operating in the steam condensing, suppression pool cooling, and shutdown cooling modes at the flow rates and temperature differentials indicated on the process diagrams. The decay ration of each controlled mode of response must be less than or equal to 0.25.	N/A	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.
SU-72	**DRYWELL COOLING SYSTEM** To verify the ability of the drywell atmosphere cooling system to maintain design conditions in the drywell during operating conditions and post-scram conditions.	Level 2 – The drywell cooling system shall maintain drywell air temperature and humidity at or below the design values as specified for the NSSS equipment.	99%	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.18.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-74	**OFFGAS SYSTEM** To verify the proper operation of the offgas system over its expected operating parameters.	Level 1 ▪ The release of radioactive gaseous and particulate effluents must not exceed the limits specified in the site Technical Specifications. ▪ Flow of dilution steam to the noncondensing stage must not fall below 92 percent of the specified normal value when the steam jet air ejectors are pumping. Level 2 ▪ The system flow, pressure, temperature, and dew point shall comply with the process data sheets supplied to the site. ▪ The catalytic recombiner, the hydrogen analyzer, the desiccant dryers, the activated carbon beds, and the filters shall be working properly during operation.	97%	Original test performed greater than or equal to 80% power. Test will be included in the EPU power ascension test plan (See Section 4.11 for EPU test description).
SU-75	**COOLING WATER SYSTEMS** To verify that the component closed cooling water system, the turbine building cooling water system, and the standby service water systems are adequate to remove plant heat loads with the reactor at rated temperature.	Level 2 – The TBCW, CCW, and SSW systems remove plant heat loads and maintain plant cooling requirements. The TBCW and CCW systems supply cooling water at 95°F or less. The SSW system supplies cooling water at 90°F or less.	100%	Original test performed greater than or equal to 80% power. Test will be included in the EPU power ascension test plan (See Section 4.11 for EPU test description).

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-76	**ENGINEERED SAFETY FEATURES (ESF) AREA COOLING** To verify that the RCIC and RHR "A" and "B" room coolers are capable of removing the postulated post-accident design heat loads.	The RCIC, and RHR "A" and "B" room coolers are capable of removing the postulated post-accident design heat loads.	N/A	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.
SU-77	**MSIV LEAKAGE CONTROL SYSTEM** To demonstrate the ability of the MSIV leakage control system to depressurize the piping between the MSIVs and outboard motor-operated isolation valve, maintain this piping at a slight sub-atmospheric pressure, and direct allowable MSIV leakage into the secondary containment for treatment by the standby gas treatment system.	Level 2 ▪ Upon being manually placed in service, the inboard and outboard MSIV-LCS subsystems initiate automatically. ▪ The inboard and outboard MSIV-LCS subsystems depressurize the piping within the allowed time limits. ▪ The inboard and outboard MSIV-LCS blowers maintain the piping between the MSIVs slightly sub-atmospheric by removing the existing MISV leakage.	N/A	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.

TABLE 9-1 EPU TEST PROGRAM EVALUATION

Original Test No.	Original Test Objective (UFSAR Section 14.2)	Original Test Acceptance Criteria	Highest Test Power Level (%OLTP)	EPU Testing Comparison
SU-78	**IN-PLANT SAFETY RELIEF VALVE TEST** ▪ To verify the design adequacy of the plant piping equipment and structures for the hydrodynamic loads imposed during actuation of the SRVs. ▪ To expand the existing Mark III containment data base to verify that the design predictions of SRV discharge, suppression pool boundary pressures, strains on submerged structures, and the response of piping equipment and buildings are conservative.	Level 1 – Criteria have been established to ensure that the plant is operated within design and Technical Specification limits as outlined by the supplemental documents which are a part of the startup test procedure. Level 2 – Criteria have been established to monitor parameters as related to expected performance during the testing as outlined by the supplemental documents which are a part of the startup test procedure.	71%	The test does not meet the CLTR, ELTR1, or SRP 14.2 guidance as a required EPU test.
SU-79	**PENETRATION COOLING** To demonstrate the ability to cool the concrete surrounding selected high temperature water-cooled and non-water-cooled pipe penetrations in the containment wall with the minimum design capability of cooling system components available.	Level 1 – The guard pipe temperature adjacent to the selected containment penetrations shall not exceed the analytically predicted value which corresponds to a maximum concrete temperature of 230°F. Level 2 - The guard pipe temperature adjacent to the selected containment penetrations shall not exceed the analytically predicted value which corresponds to a maximum concrete temperature of 200°F.	TC6 Window (95%-100%)	Original test performed greater than or equal to 80% power. Justification for eliminating this test from the EPU Test Program is provided in Section 3.19.

TABLE 9-2 EPU IMPLEMENTATION MODIFICATIONS

Modification	Description	Anticipated Post-Modification Testing
Auxiliary Cooling Tower Expansion	• Eight (8) cells added to tower	• Scheme Checks • Fan Motor Testing • Vibration Monitoring • System Performance Test
Upgrade Drain System Level Control Valves	• Modification of several normal and alternate drain valves	• Calibration and Tuning of Level Control System • System Performance Test
Feedwater Heater Upgrade	• Replace second, third, and fourth stage feedwater heaters (three heaters in each stage) • Increase loop seal drain piping size for the high pressure 5A and 5B feedwater heaters • Replace 1st, 5th, and 6th stage feedwater heater vent orifices • Replace liners for the expansion joints located in the lines to the 2nd stage feedwater heaters • Reconfigure extraction steam lines to feedwater heaters	• Non-Destructive Examinations • Operational Leak Tests • Calibration and Tuning of Level Control System
Circulating Water Pump Upgrade	• Replace circulating water pump impellers	• Motor Testing • Vibration Monitoring • Performance Testing
Zinc Injection Passivation System Modification	• Replace flow control valve trim • Upgrade Strainer	• In-Service Leak Test • System Performance Test
Condenser	• Condenser structural enhancement • Condenser tube staking	• Non-Destructive Examination

TABLE 9-2 EPU IMPLEMENTATION MODIFICATIONS

Modification	Description	Anticipated Post-Modification Testing
Main Transformer Replacement	• Replace all three main transformers (and installed spare).	• Applied Potential (Hi Pot) • Relay Calibrations • Gas Levels (Baseline) • Scheme Checks • Logic Testing • Thermography • Performance Test • Transformer Utilities Checks • Transformer Utilities Performance Checks
Increase Ultimate Heat Sink Water Supply	• Extend the existing siphon connecting the Unit 1 UHS basin with the Unit 2 UHS basin	• Non-Destructive Examination
Reactor Feedwater Pump Upgrade	• Replace reactor feedwater pump turbine rotors	• Operational Leak Test • Vibration Monitoring • Feedwater Flowrate Increase Verification
Equipment Qualification Modifications	• Replace motor; position and torque switches; and scotch tape splices for 13 RHR motor operated valves • Replace hook-up wire for the two hydrogen analyzer panels • Scotch tape splices for RHR jockey pump power cables	• Logic System Function Testing • Code Testing (IST, Appendix J) • MOV Signature Testing • Functional Test • Functional Test • IST Test

TABLE 9-2 EPU IMPLEMENTATION MODIFICATIONS

Modification	Description	Anticipated Post-Modification Testing
Component Cooling Water Modifications	• Install CCW heat exchanger tube cleaning system.	• Performance Test
Turbine-Generator Modifications	• Replace the high pressure turbine for increased steam flow at EPU conditions • Generator rotor and stator upgrade (1600 Mva) • Seal oil skid upgrade • Generator hydrogen and exciter air cooler refurbishment • Replace main generator current transformers	• 120% Rotor Speed Factory Testing • Transient/Steady State Data Recording • Overspeed Trip Test • In-Service Leak Test • Calibrate and Test Pressure Control Systems • Stator and Rotor Acceptance Testing • HP Turbine Flow Guarantee Testing • Primary Water Leakage Testing • Potential Transformer Scheme Verification • Seal Oil Skid Performance Testing • Hydrogen and Exciter Air Cooler Performance Testing
Temporary Vibration Monitoring	• Install accelerometers on Main Steam, Feedwater, Extraction Steam and BOP piping for vibration monitoring (temporary)	• Functional Checks • Data acquisition Checks
Instrument Replacement and Modification	• See PUSAR Table 2.4-2 for list of instruments	• Scheme Checks • Instrument / Loop Calibration

TABLE 9-2 EPU IMPLEMENTATION MODIFICATIONS

Modification	Description	Anticipated Post-Modification Testing
CCW Heat Exchanger Control Valve	• Modify PSW Control Valve for the CCW Heat Exchangers	• Non-Destructive Testing • Control Loop Calibration • Performance Testing • Flow Balance of PSW System
Generator Isolated Phase Bus Duct Cooling Capacity	• Replace the Isophase bus duct cooler and fans	• Scheme Checks • Logic Testing • Loop Calibrations • Flow Balance • Vibration Monitoring • Performance Test
Standby Liquid Control System	• Upgrade to enriched boron system	• Relevant Surveillance Testing in accordance with Technical Specification 3.1.7
Steam Dryer Upgrade	• Replace reactor pressure vessel steam dryer	• See Attachment 11 of this License Amendment Request for Steam Dryer Testing Requirements
Condensate Full Flow Filtration (CFFF) Installation	• Install a new system with sufficient filter capacity for 100% condensate flow • Provide automatic bypass of CFFF	• Scheme Checks • Logic Testing • Loop Calibrations • Non-Destructive Examination • Functional Tests of Automatic Bypass, Manual Bypass and Override • System Performance Test

TABLE 9-2 EPU IMPLEMENTATION MODIFICATIONS

Modification	Description	Anticipated Post-Modification Testing
Main Steam Line Vibration Monitoring Strain Gauges	• Install strain gauges to record the dynamic pressure fluctuations inside the main steam piping in the drywell. (These were installed in RF16 to gather data and used for the current dryer analysis. Will need to be checked and verified prior to RF18 Startup.)	• Functional Checks • Data acquisition Checks
Moisture Separator/Reheater (MSR) Modifications	• Replace MSR shell and internals • Install additional MSR relief valve	• Scheme Checks • Logic Testing • Loop Calibrations • Non-Destructive Examination • Bench Test of Relief Valve • Operational Leak Test
FPCC Heat Exchanger Upgrade	• Install additional heat exchanger capacity.	• Non-Destructive Examination • Valve Logic Test • Operational Leak Test • Heat Exchanger Capacity Test
Plant Service Water Radial Well Addition	• Provide additional cooling capacity via installation of a new well #6.	• Scheme Checks • Logic Testing • Non-Destructive Examination • Pump Motor Testing • Vibration Monitoring • System Performance Test

TABLE 9-3
EPU TEST 2 RADIATION MEASUREMENT LOCATIONS

Gamma Radiation Locations (All Test Conditions)		Gamma Radiation Locations (100% EPU Power Only)		Neutron Radiation Locations (All Test Conditions)	
Location	**Dose Rate (mr/hr)[1]**	**Location**	**Dose Rate (mr/hr)[1]**	**Location[2]**	**Dose Rate (mr/hr)[1]**
166 TB North	6	A RFPT	230	Cont Bldg 208 – A1	<0.5
166 TB South	4	B RFPT	160	Cont Bldg 208 – A2	<0.5
166 TB West	15	133 TB Truck Bay	0.8	Cont Bldg 208 – A3	<0.5
Unit 1 TB Crane	7	133 TB Sliding Door	0.08	Cont Bldg 208 – A4	<0.5
Unit 2 TB Crane	51	133 TB Insul. Shop	0.006	Cont Bldg 120 – A51	25
MCC Area	8	Unit 1 Turb Roof	350	Cont Bldg 120 – A53	<0.5
Off line SJAE Room	3	Maint. Shop	.025	Cont Bldg 120 – A54	<0.5
Circ Water Crane	1.7	M&E Bldg	.02	Cont Bldg 135 – A56	<0.5
Unit 2 166 TB Deck	2.5	Guard Tower 1	0.62	Cont Bldg 135 – A58	<0.5
Unit 2 Roof	5	Guard Tower 2	0.18	Cont Bldg 135 – A61	1.5
Unit 1 Aux Roof	3	Guard Tower 3	0.07	Cont Bldg 135 – A62	1.0
RW Roof	10	Guard Tower 4	0.015	Cont Bldg 161 – A63	<0.5
166 TB (ARM 1)	-	North of Turb Bldg	.04	Cont Bldg 161 – A66	2.5
166 TB (ARM 2)	4000	East of Turb Bldg	0.25	Cont Bldg 161 – A68	0.8
166 TB (ARM 3)	2300	Warehouse Unit 1	0.03	Cont Bldg 161 – A69	<0.5
133 RFPT (ARM 1)	50	GE/West Bldg	0.03	Cont Bldg 184 – A70	<0.5
133 RFPT (ARM 2)	26	Warehouse Unit 2	0.012		
133 C Bay (ARM 3)	11000	Switchyard	0.06		
133 C Bay (ARM 4)	1800	Security Island	0.01		
113 C Bay (ARM 1)	1400	Fab Shop	0.03		
113 C Bay (ARM 2)	3200	QA Offices	0.01		
SJAE A (ARM)	-	Fort Coker	0.014		
SJAE B (ARM)	850	Admin Parking Lot	0.013		
87 TB (ARM)	900	Process Facility	0.010		
		North Gate	0.004		
		South Gate	0.008		
		Cooling Tower	0.020		
		ESC	0.008		
		MSL A	3310		
		MSL B	2530		
		MSL C	3830		
		MSL D	2010		

Notes: 1 – Represents the maximum dose rate recorded during previous testing.
2 – Neutron monitoring location Point ID numbers are provided on Original Startup Test (1-000-SU-02-6)

Attachment 10

GNRO-2010/00056

Vibration Analysis and Testing Program

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1.0 INTRODUCTION

This Attachment provides a detailed discussion of the analyses and testing program undertaken to provide assurance that unacceptable flow induced vibration (FIV) issues are not experienced at Grand Gulf Nuclear Station (GGNS) due to extended power uprate (EPU) implementation for affected piping system.

Increased flow rates and flow velocities during operation at EPU conditions are expected to produce increased FIV levels in some systems. As discussed in Section 3.4 of Licensing Topical Report (LTR) NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," the Main Steam System (MSS) and Feedwater System (FWS) piping vibration levels should be monitored because their system flow rates will be significantly increased (Reference 7.1). While a review of industry EPU operating experience identified very few component failures that can be attributed to EPU, most of these failures were related to FIV.

In December 2008, the Boiling Water Reactor Owners' Group (BWROG) issued NEDO-33159, Revision 2, "Extended Power Uprate (EPU) Lessons Learned and Recommendations," based on operating experience (OE) and evaluations from Boiling Water Reactor (BWR) plants that have previously implemented EPUs and from plants currently performing pre-EPU evaluations (Reference 7.2). NEDO-33159 Section 3.11 states:

> "Since the majority of EPU-related component failures involve flow induced vibration, the BWROG EPU Committee held a vibration monitoring and evaluation information exchange meeting of industry experts in June 2004. The committee determined that the current process of monitoring large bore piping systems in accordance with the requirements of American Society of Mechanical Engineers (ASME) Operation and Maintenance (O&M) Part 3 is sufficient to preclude challenges to safe shutdown. Increases in large bore piping vibration levels are a precursor to increased vibration levels in attached small bore piping and components."

Regulatory Guide (RG) 1.20, "Comprehensive Vibration Assessment Program for Reactor Internals during Preoperational and Initial Startup Testing," was revised in 2007 to Revision 3. In addition to guidance for vibration assessment of reactor internals, this regulatory guide provides helpful information on methods for evaluating the potential adverse effects from pressure fluctuations and vibrations in piping systems for boiling water reactor (BWR) nuclear power plants. However, additional guidance is provided with regard to piping vibration. The guidance is primarily directed to initial start-up of new plants, with general guidance interpreted for use in power uprate power ascension testing. Where applicable, this guidance has been incorporated into the EPU monitoring program for piping vibration at GGNS.

In addition to MSS and FWS, the related Extraction Steam (EXS), Condensate (CDN), Moisture Separator (M/S) and Heater Drain (HD) systems also experience similar flow increases under EPU conditions and are included in the EPU vibration monitor program. Other systems experience insignificant or no increase in flow and, therefore, are not included in this program.

Review of previous vibration data collected during initial start-up testing and power ascension to original licensed power levels indicates relatively low vibration levels. Extrapolation of this earlier data to EPU power levels indicates that vibration of piping and components will not be adversely affected by EPU operation.

This document describes the piping vibration monitoring program to be implemented at GGNS during power ascension to confirm acceptable vibration levels at EPU power. It addresses systems impacted by EPU. It compares previously collected vibration data to conservative projections for EPU vibration levels based on increases in vibration being proportional to increases in flow rate squared. This document also describes the techniques to be used for collecting and storing the vibration data as well as the acceptance criteria to be used for evaluation of that data.

2.0 ACCEPTANCE CRITERIA

Acceptance criteria for evaluating the alternating stress due to flow induced vibration is based on the guidance of the ASME OM-S/G Part 3 (Reference 7.3), which stated that for steady state vibration, the maximum calculated alternating stress shall not exceed S_{el}/α. The governing equation from OM-S/G Part 3 for the alternating stress criteria is given below:

$$S_{alt} = C_2 K_2 M / Z \leq S_{el}/\alpha$$

Where:

S_{alt} =Alternating stress intensity

C_2 =Secondary stress index as defined in ASME III Code

K_2 =Local stress intensification factor as defined in ASME III Code

M =Maximum zero to peak dynamic moment loading due to vibration only

Z =Section modulus of the pipe

S_{el} =0.8 S_A, where S_A is the alternating stress at 10^6 cycle from Figure I-9.1, or S_A at 10^{11} cycles from Figure I-9.2.2 of the ASME Code, Section III

α =Allowable stress reduction factor, 1.3 for material covered by Figure I-9.1 or 1.0 for material covered by Figure I-9.2.1 or 9.2.2 of ASME Code, Section III

For ASME III Class 2 and 3 Piping, or ANSI B31.1, the $C_2 K_2$ = 2*i and " i " is the stress intensification factor, as defined in Sub-Section NC and ND of the ASME Code, Section III or ANSI B31.1. The maximum allowed alternating stress intensity is:

- Carbon steel material, S_A = 12,500 psi, α is 1.3, then, S_{alt} =0.8*12,500/1.3= 7,692 psi
- Stainless steel material, S_A = 13,600 psi, α is unity, then, S_{alt} =0.8*13,600= 10,880 psi

3.0 SUSCEPTIBILITY AND MONITORING

The MSS and FWS piping will experience higher mass flow rates and flow velocities under EPU conditions. When power is increased from current licensed thermal power (CLTP) to EPU conditions, steady state FIV levels are conservatively expected to increase in proportion to the fluid density (ρ) and the square of the flow velocity (V) or ρV^2. Thus, the vibration levels of the MSS and FWS piping are expected to increase by approximately 35% and 37 % based on flow increase of 16% for Main Steam and 17% for Feedwater, respectively. Tested vibration levels in the main piping of MSS and FWS greater than 50% of the EPU acceptance criteria will result in an engineering evaluation of the attached branch piping connections to ensure that the steady state stresses are within the endurance limit. Other possible sources of increased vibration, such as flow instabilities or acoustic resonance as a result of increased flow velocities, may contribute to EPU vibration levels. These mechanisms cannot be quantified analytically. Hence a piping vibration test program during initial EPU operation is needed.

Flow rates in portions of the Condensate (CDN), Extraction Steam (EXS), High Pressure Heater Drain (HDH), Low Pressure Heater Drain (HDL) and Moisture Separator (M/S) Drain systems increase similarly to MSS and FWS, and are therefore susceptible to increased vibrations at EPU conditions.

Other systems will see either no increase or negligible increase in flow.

Based on the potential for significantly increased vibrations on the systems identified above, a confirmatory test program will be implemented to monitor piping and attached component vibration levels on the identified systems during initial power ascension to EPU conditions.

Piping inside containment and inaccessible piping outside containment will be monitored using accelerometers installed at selected locations on the piping and attached components. The accelerometers will be wired to remote data acquisition systems (DAS) located in the Auxiliary and Turbine buildings.

Piping outside containment that is accessible during plant operation will be monitored by performing visual observations and by taking vibration measurements using hand-held vibration instruments during power ascension to EPU conditions.

Small bore branch piping is susceptible to the effects of the associated large bore piping FIV. Walkdowns of the systems impacted by EPU flow increases have been performed to identify if there are any additional potentially susceptible small bore line configurations. Susceptible small bore branch lines will be monitored for vibration during EPU power ascension using a combination of accelerometers and visual inspection to confirm that vibrations are within acceptable limits. Cantilevered vent and drain piping vibration will be monitored per existing program.

4.0 RESULTS FROM PREVIOUS VIBRATION TEST PROGRAMS AND EPU PROJECTIONS

Vibration levels at Original Licensed Thermal Power (OLTP, 3833 MWt) were obtained during initial plant start-up testing (Reference 7.4). The results of initial startup vibration monitoring form part of the basis for the vibration monitoring to be performed during EPU power ascension.

The vibration monitoring program implemented during initial plant startup at GGNS included systems in the EPU vibration monitoring scope. The projected EPU vibration levels are calculated using the following equation:

$$\text{EPU vibration level} = (\text{OLTP vibration level}) * (\text{EPU flow rate} / \text{OLTP flow rate})^2$$

For EPU vibration criteria, Reference 7.3, ASME OM-S/G, “Standards and Guides for Operation and Maintenance of Nuclear Power Plants”, Part 3, Non-mandatory Appendix D velocity criteria 0.5 inches per second as the screening criteria will be used for balance of plant piping outside containment. This is derived to indicate safe level of vibration for any type of piping configuration. Using this criterion, piping systems can be checked and those with vibration velocity levels lower than the screening value would require no further analysis. If vibration velocities greater than 0.5 inches per second are measured, then further analyses are required to determine acceptability. The projected EPU vibration levels are also presented in terms of the acceptance criteria established for the EPU vibration monitoring program. The OLTP vibration levels and projected EPU vibration levels and piping monitoring locations in turbine building are summarized in Tables 4-1 for the Feedwater and Condensate systems.

Table 4-1: Previous OLTP Results and EPU Projections for Turbine Building Monitoring Locations

System	Piping Segment	Monitoring Location	Measured Vibration Resultant velocity, in/sec	EPU Factored Vibration Resultant velocity, in/sec	Max Screening Criteria, in/sec	Remarks
FWS	12”-CBD-2	At support N1N21G001R02 near Reactor Feed Pump 1N21C001A Discharge (HL-1323A)	0.297	0.407	0.50	
CDN	24”-GBD-21	Condensate pumps discharge header between 1N19C003B& C (HL-1322A)	0.283	0.388	0.50	Note 1
CDN	18”-GBD-19	5’-0” east of support N1N19G001H009, (HL-1322A)	0.262	0.359	0.50	Note 2
CDN	24”-GBD-28	Condensate Booster Pump suction after cleanup system at Support N1N19G002H08 (HL-1322B)	0.291	0.399	0.50	
CDN	14”-GBD-17	At support N1N19G002H14 (HL-1322B)	0.688	0.943	0.50	Note 3
CDN	14”-FBD-2	At support N1N19G003H21 El 105’-3” (HL-1322C)	1.173	1.607	0.50	Note 3
CDN	14”-FBD-2	At one foot above valve, 1N19F046A EL 117’-8” (HL-1322C)	0.326	0.447	0.50	
CDN	24”-FBD-24	On horizontal run above valve 1N21F029B (HL-1322E)	0.466	0.638	0.50	Note 3
CDN	24”-FBD-24	On vertical run just below valve 1N21F029A (HL-1322E)	0.258	0.353	0.50	

Notes: 1. Y and Z directions, horizontal perpendicular and vertical velocity measurements only
2. X and Y directions, horizontal perpendicular and vertical velocity measurements only
3. Evaluation of the measured vibration results is shown in Section 4.0 in the following paragraph.

The above vibration velocity data was obtained using hand held Vibragraph with reactor at full power. It should be noted that the accuracy of the hand held meters was somewhat limited due to the low frequency roll off characteristics of the device.

Throughout the test, a few high vibration levels were noted, several of which were resolved by the addition of new rigid pipe supports. Particularly the small bore lines, simple hanger adjustments were made necessary to resolve the vibration conditions.

At the monitoring location at support N1N19G002H14, the measurement data showed a high velocity. However, as shown on the hanger drawing, there are support modifications at the adjacent locations as compared with the Pre-Op Piping drawing. It is likely that the measurement was taken before the support modifications were implemented. This location will be monitored during power ascension to EPU.

At the monitoring location at support N1N19G003H21 on line 14”-FBD-2, the measurement data showed a relatively high velocity. This location is immediately downstream of the Condensate Booster Pump A. The measurement data may reflect the short term transient event of the pump operation during pump startup/stop event and not the case of long term flow induced vibration as evidenced by the measurement data shown on the same line downstream not far from N1N19G003H21 at one foot above valve N19F046A, which showed substantially lower velocity well below 0.5 inches per second. Therefore, this location will be included as monitoring point during power ascension to EPU.

At the monitoring location on horizontal piping above valve N21F029B, the measurement data showed a relatively high velocity. This location is right at the suction side of the Reactor Feed Pump B. The measurement data may reflect the short term transient event of the pump operation during pump startup/stop event and not the case of long term flow induced vibration. Therefore, this location will be included as a monitoring point during power ascension to EPU.

The above vibration monitoring locations are included and accepted in the document, “Special Test-Visual Steady–State Vibration Monitoring Program, 1C88-ST01, June 13, 1986” in Reference 7.4, as the additional dynamic vibration points other than the baseline vibration points, indicating one (1) additional point each at the suction and discharge side in the vicinity of the pump are selected for the pump start/stop events. This is for the short term transient event and is not affecting the long term flow induced vibration on the piping.

Higher vibrations in the turbine building are expected because the piping is generally less rigidly restrained.

The results of the representative high vibration levels at the previously measured locations were presented in Table 4-1. Based on current plant operation history and reasons stated in the previous paragraph, vibrations at EPU conditions are expected to remain well within acceptable limits. Although there is no base line flow induced vibration data available for the MSS and FWS piping at the point of interest, the expected vibration levels of the main MSS and FWS pipes are anticipated to be low, similar to the measured vibration levels of MSS and FWS piping in other BWR plants. Hence, the vibration levels of the branch piping attached to the main piping are not of concern.

5.0 EPU VIBRATION MONITORING PROGRAM

5.1 Overview

Vibration levels at Original Licensed Thermal Power (OLTP, 3833 MWt) were documented during initial plant start-up testing. Vibration measurement locations and levels from the earlier vibration testing for Feedwater and Condensate systems are summarized in Table 4-1. These earlier test programs form part of the basis for the vibration monitoring to be performed during EPU power ascension.

Additional analyses using more detailed methods have been performed for Main Steam and Feedwater systems to establish EPU vibration monitoring locations and acceptance criteria. The monitoring point for FWS identified in Table 4-1 has been reassessed based on the analysis results. Additional monitoring points have been identified on systems not previously instrumented that have significant flow increases as a result of EPU. The EPU analysis and flow increase evaluation results form the rest of the bases for EPU vibration monitoring.

Locations inside containment and inaccessible locations outside containment will be monitored using accelerometers installed at selected locations on the piping and attached components. The accelerometers will be wired to remote data acquisition systems (DAS) located in the Auxiliary and Turbine buildings.

Piping outside containment that is accessible during plant operation will be monitored by performing visual observations and by taking vibration measurements using hand-held vibration instruments during power ascension to EPU conditions.

5.2 Vibration Monitoring Location and Acceptance Criteria Development

5.2.1 MSS and FWS Piping (Inside and Outside Containment)

Detailed models of the MSS and FWS piping for both inside containment and outside containment were developed for this evaluation. A “1g” broad-band uniform amplified response spectrum (ARS) was applied up to 250 Hz in each three orthogonal directions for MSS and FWS piping. Static loads, such as weight and thermal expansion, are not considered since these loads do not contribute to cyclic vibratory loading of the piping system. Additionally, seismic (inertia and anchor movements) and turbine stop valves loads are not considered, since these loads are transient dynamic loads that do not contribute to the steady-state cyclic vibratory loading of the system.

The frequency content due to steady state vibration is typically broad band so the acceptance criteria was developed using an equivalent root mean square (RMS) input that would contain energy over the entire frequency range of interest. This differs from the “classical piping analysis” such as seismic analysis where the magnitude of the input amplified response spectra (ARS) varies with frequency. The calculated stresses used to develop the acceptance criteria are conservative since every frequency is assumed to have the same input magnitude.

The results of the piping analysis are provided in terms of accelerations, displacements, and the stresses at each node. The overall values at each node were obtained by combining the results for all three orthogonal directions using the Square Root of the Sum of Squares (SRSS) method. Adjustment factors (calculated using the maximum endurance stress values and the

guidance of ASME O&M-S/G Part 3) and the maximum stress values (from the piping analysis) for each of the maximum alternating stress intensity locations.

Allowable displacement (inches zero-peak) and acceleration (g's-peak) limits at the selected measurement locations were calculated based on the analysis results and ASME endurance stress limits for steady state vibration per ASME O&M-S/G Standards and Guidelines Part 3 (Reference 7.3). The primary acceptance criteria are in terms of displacement, which is directly proportional to pipe stress. Secondary acceptance criteria in terms of acceleration were determined for use in the event of difficulties that may occur in accurately double-integrating the measured accelerations to displacements.

The displacement limits are applicable for vibration frequencies up to 250 Hz, which covers the frequency range in which the most significant structural displacement responses are expected. Piping displacements due to excitation frequencies above 50 Hz are typically insignificant relative to the lower frequency displacements. The MSS and FWS acceleration limits are applicable for frequencies up to 250 Hz. However, significant forcing frequencies and structural responses above 50 Hz are not expected in the MSS and FWS system.

Main Steam and Feedwater System - Inside Containment

Detailed models of the MSS and FWS piping inside containment were developed for this evaluation. A "1g" broad-band uniform amplified response spectrum (ARS) was applied up to 250 Hz in each three orthogonal directions for MSS and FWS piping inside containment. Adjustment factors (calculated using the maximum endurance stress values and the guidance of ASME O&M-S/G Part 3) and the maximum stress values (from the piping analysis) for each of the maximum alternating stress intensity locations are as follows:

Table 5.1: Maximum Stress and Adjustment Factors for MSS and FWS Piping Segments -- Inside Containment

System Name	Node Point	Piping Location	Max Alternating stress, psi	Adjustment Factor, F_{adjust}
MSS-Loop A	9	Sweepolet at Main Steam Pipe Loop A & SRV Q1B21F041A inlet pipe	15,789	0.487
MSS Loop C	10	Sweepolet at Main Steam Pipe Loop C & SRV Q1B21F041C inlet pipe	15,483	0.497
FWS- Loop B	335	At 12"-DBA-17 and RPV nozzle Interface (HL-1328J)	11,058	0.696

The acceptance criteria are then calculated by multiplying the accelerations and the displacements by the adjustment factors in Table 5.1. Sample of calculations for maximum accelerations (A_{calc}) and maximum displacements (D_{calc}) at Node 5 on Main Steam piping Loop A, are provided below:

Node point 5, accelerations (g):

$A_x = A_{xcalc} * F_{adjust} = 1.128\ g * 0.487 = 0.550\ g$

$A_y = A_{ycalc} * F_{adjust} = 0.877\ g * 0.487 = 0.427\ g$

$A_z = A_{zcalc} * F_{adjust} = 0.930\ g * 0.487 = 0.453\ g$

Node point 5, displacements (inches);

$D_x = D_{xcalc} * F_{adjust} = 0.025 * 0.487 = 0.012$ inches

$Dy = D_{ycalc} * F_{adjust} = 0.011 * 0.487 = 0.005$ inches

$D_z = D_{zcalc} * F_{adjust} = 0.029 * 0.487 = 0.014$ inches

The vibration monitoring locations were selected where, based on the "1g" spectra analysis results, significant displacements or accelerations occurred relative to other locations. The measurement locations were also selected such that the general overall piping responses were high such that significant vibrations would not be missed. Where applicable, symmetry between trains or loops was considered to remove redundancy to reduce the overall number of monitoring locations. The EPU vibration monitoring locations determined for the MSS and FWS piping inside containment from the analyses are summarized in Tables 5.2 for Main Steam piping and Table 5.3 for Feedwater piping. GGNS has performed analyses and testing which investigated and addressed the potential for acoustic resonance due to the increased steam flow past the safety relief valve (SRV) standpipe, as well as other branch connections, and concluded that the onset of vortex shedding acoustic resonance could be expected beyond EPU power steam flow rates. Therefore, SRV vibration resulting from acoustic resonance is not expected at the EPU operating conditions. However, monitoring locations were also selected for Main Steam safety-related valve (SRV) to identify SRVs which are susceptible to potential flow induced vibration/vortex resonance, as shown in Table 5.2.

Table 5.2: EPU Monitoring Locations for MSS Inside Containment

System	Piping Segment	Monitoring Location-Direction	EPU Allowable Acceleration, g	Max Allowable Acceleration, g	Description
MSS	Loop A Node Point 5	5-X	0.413	0.550	At support 769E453-S102A on GE Drawing 769E453
MSS		5-Y	0.320	0.427	
MSS		5-Z	0.340	0.453	
MSS	Loop A Node Point 8	8-X	0.385	0.513	At support 769E453-H101A on GE Drawing 769E453
MSS		8-Y	0.230	0.306	
MSS		8-Z	0.402	0.536	
MSS	Loop B Node Point 9	9-Z	0.410	0.547	At support 769E453-H101B on GE Drawing 769E453. Measure one direction only
MSS	Loop C Node Point 9	9-X	0.407	0.542	At support 769E453-H101C on GE Drawing 769E453
MSS		9-Y	0.318	0.424	
MSS		9-Z	0.410	0.547	
MSS	Loop C Node Point 500	500-X	0.367	0.489	At support 769E453-H102C on GE Drawing 769E453
MSS		500-Y	0.499	0.665	
MSS		500-Z	0.356	0.474	
MSS	Loop D Node Point 8	8-Z	0.402	0.536	At support 769E453-H101D on GE Drawing 769E453. Measure one direction only

System	Piping Segment	Monitoring Location- Direction	Max Allowable Acceleration, g	Description
MSS	Loop A Node Point 49	49-X	0.1	At SRV Q1B21F041A on GE Drawing 767E799
MSS		49-Y	0.1	
MSS		49-Z	0.1	
MSS	Loop A Node Point 97	97-X	0.1	At SRV Q1B21F047A on GE Drawing 767E799
MSS		97-Y	0.1	
MSS		97-Z	0.1	
MSS	Loop C Node Point 63	63-X	0.1	At SRV Q1B21F051C on GE Drawing 767E799
MSS		63-Y	0.1	
MSS		63-Z	0.1	
MSS	Loop C Node Point 109	109-X	0.1	At SRV Q1B21F047L on GE Drawing 767E799
MSS		109-Y	0.1	
MSS		109-Z	0.1	

Table 5.3: EPU Monitoring Locations for FWS Inside Containment

System	Piping Segment	Monitoring Location-Direction	EPU Allowable Acceleration, g	Max Allowable Acceleration, g	Description
FWS	Loop B Node Point 30	30-X	0.597	0.796	At support Q1B21G026R03 on HL-1328J
FWS		30-Y	0.821	1.094	
FWS		30-Z	1.019	1.358	
FWS	Loop B Node Point 50	50-X	0.880	1.173	At support Q1B21G026H04 on HL-1328J
FWS		50-Y	0.971	1.295	
FWS		50-Z	0.698	0.930	
FWS	Loop B Node Point 65	65-X	0.359	0.479	At support Q1B21G026H03 on HL-1328J
FWS		65-Y	0.644	0.859	
FWS		65-Z	0.684	0.912	
FWS	Loop A Node Point 30	30-X	0.597	0.796	At support Q1B21G026R08 on HL-1328J
FWS		30-Y	0.821	1.094	
FWS		30-Z	1.019	1.358	

Main Steam and Feedwater System – Outside Containment

Detailed models of the MSS and FWS piping outside containment were also developed for this evaluation. A “1g” broad-band uniform amplified response spectrum (ARS) was applied up to 250 Hz in each three orthogonal directions for MSS and FWS piping. Adjustment factors (calculated using the maximum endurance stress values and the guidance of ASME O&M-S/G Part 3) and the maximum stress values (from the piping analysis) for each of the maximum alternating stress intensity locations are as follows:

Table 5.4: Maximum Stress and Adjustment Factors for MSS and FWS Piping Segments - Outside Containment

System Name	Node Point	Piping Location	Max Alternating stress, psi	Adjustment Factor, F_{adjust}
MSS	952	At the end of the valve 1N11F001B on line 18”- DBD-59 (HL-1320C)	41,205	0.1867
FWS	910	At 12”-GBD-69 and HP condenser shell Nozzle (HL-1323A)	175,920	0.0437

The acceptance criteria are then calculated by multiplying the accelerations and the displacements by the adjustment factors in Table 5.4

The EPU vibration monitoring locations determined for the MSS and FWS piping outside containment from the analyses are summarized in Tables 5.5 and 5.6 respectively.

Table 5.5: EPU Monitoring Locations for MSS Outside Containment

System	Piping Segment	Monitoring Location-Direction	EPU Allowable Displacement, inches	Max Allowable Displacement, inches	Description
MSS	Node Point 410	410-X	0.245	0.326	At Tee on line 28”-DBD-56 at El 156’-0” west of support, N1N11G001H14 (HL-1320A). Measure 2–directions only
MSS		410-Y	0.003	0.004	
MSS		-	-	-	
MSS	Node Point 839	839-X	0.005	0.006	On line 6”-DBD-1 at support N1N11G004H04 EL 144’-0” (HL-1320B)
MSS		839-Y	0.008	0.011	
MSS		839-Z	0.010	0.013	

System	Piping Segment	Monitoring Location-Direction	EPU Allowable Acceleration, g	Max Allowable Acceleration, g	Description
MSS	Node Point 17753	17753-X	1.310	1.746	On vertical pipe below elbow (EL 154’-0”) on 8”-DBD-60 (HL-1320B)
MSS		17753-Y	0.402	0.536	
MSS		17753-Z	0.953	1.270	
MSS	Node Point 943	943-X	0.414	0.552	On elbow (EL 133’-6 ¼”) west of support N1N11G003H04 on line 18”-DBD-59 (HL-1320C)
MSS		943-Y	0.564	0.752	
MSS		943-Z	0.321	0.428	

Table 5.6: EPU Monitoring Locations for FWS Outside Containment

System	Piping Segment	Monitoring Location- Direction	EPU Allowable Displacement, inches	Max Allowable Displacement, inches	Description
FWS	Node Point 725	725-X	0.056	0.074	On elbow south of the support N1N21G001H11 at El 152'-3" on 18"-DBD-20 (HL-1323A)
FWS		725-Y	0.041	0.055	
FWS		725-Z	0.088	0.117	
FWS	Node Point 895	895-X	0.029	0.038	On elbow south of the support N1N21G001H28 at EL 124'-3" on 12"-CBD-2 (HL-1323A)
FWS		895-Y	0.002	0.003	
FWS		895-Z	0.180	0.240	

System	Piping Segment	Monitoring Location- Direction	EPU Allowable Acceleration, g	Max Allowable Acceleration, g	Description
FWS	Node Point 950	950-X	0.052	0.069	On elbow on 12"-DBD-21 at El 149'-10 3/4"(HL-1323A)
FWS		950-Y	0.065	0.087	
FWS		950-Z	0.093	0.124	
FWS	Node Point 11303	11303-X	0.159	0.212	At elbow on line 6"-DBB-88 east of support Q1E12G021C02 (HL-1328K)
FWS		11303-Y	0.140	0.186	
FWS		11303-Z	0.080	0.107	

5.2.2 CDN, EXS, HDH and HDL Piping (Outside Containment)

Significant flow increases occur in portions of the Condensate, Extraction Steam and Heater Drain systems as a result of EPU. Monitoring locations were selected on the basis of locations previously monitored during initial plant startup, percent flow increase due to EPU, projected EPU flow rates, piping configuration and similarity between trains.

Condensate Piping

The condensate system experiences flow increases similar to FWS as a result of EPU. Eight (8) locations from the initial startup monitoring locations were selected for EPU vibration monitoring. These locations will be instrumented in each of the following condensate systems:

- Condensate Pumps to Condensate Cleanup
- Condensate Cleanup to Condensate Booster Pumps
- Condensate Booster Pumps to Feedwater Heaters
- Feedwater Heaters to Reactor Feed Pumps

Table 5.7: EPU Monitoring Locations for Condensate System

System	Piping Segment	Monitoring Location	Max Screening Resultant Velocity, in/sec	Description
CDN	24”-GBD-21	At El-88’-8”	0.50	Condensate pumps discharge header between pumps 1N19-C003B & C, (HL-1322A)
CDN	18”-GBD-19	At El 83’-4”	0.50	5’-0” east of support N1N19G001H009, (HL-1322A)
CDN	24”-GBD-28	At El 137’-10”	0.50	Condensate Booster Pump suction after cleanup system at support N1N19G002H08 (HL-1322B)
CDN	14”-GBD-17	At El 144’-0”	0.50	At support N1N19G002H14, (HL-1322B)
CDN	14”-FBD-2	At El 105’-3”	0.50	At support N1N19G003H21, (HL-1322C)
CDN	14”-FBD-2	At El 117’-8”	0.50	At one foot above valve 1N19F046A, (HL-1322C)
CDN	24”-FBD-24	At El 150’-6 3/8”	0.50	On horizontal run above valve 1N21F029B, (HL-1322E)
CDN	24”-FBD-24	At El 145’-0”	0.50	On vertical run just below valve 1N21F029A (HL-1322E)

Extraction Steam Piping

The extraction steam system will experience insignificant flow velocity increases or some reduction in flow velocity at EPU, for the 1st point, 2nd point, 4th point and 5th point heater. Minor increase up to 8 percent is expected for 6th point heater. For 3rd point heater, up to 17 percent increase is expected.

There is one line each (36 inches in size) that makes up the extraction steam system from the low pressure (LP) turbine to the three trains of the 3rd point heaters. These extraction steam lines are located inside the condenser. Although during EPU these lines will experience increase in flow velocity of about 17 percent, they are not to be instrumented since these lines are short and the velocities at EPU is lower than the industrial velocity design standard of 167 feet per second for wet steam.

The extraction steam lines from the cross-around steam pipe to the 5th point heaters are two 24-inch lines. EPU will result in insignificant velocity increase. Therefore, 24-inch extraction steam lines to the 5th point heaters are not instrumented.

There are 2 lines in total that make up the extraction steam system from the high pressure (HP) turbine to the two trains of the 6th point heaters. These extraction steam lines from the HP turbine to the 6th point feedwater heaters are 24-inch in size. They are routed and supported in a similar way. EPU will experience increase in flow velocity of up to 8 percent. One 24-inch line will be instrumented with accelerometers in all three (3) orthogonal directions.

Table 5.8: EPU Monitoring Locations for Extraction Steam System

System	Piping Segment	Monitoring Location	Max Screening Resultant Velocity, in/sec	Description
EXS	24”-GBD-1	EL-145’-8 1/4”	0.50	Near support N1N36G001H03 (HL-1321A)

Moisture Separator and Feedwater Heater Drain Piping

The Moisture Separator and Heater drain system will experience significant flow increases in several areas. Monitoring locations on the drain piping were selected as discussed below:

High Pressure Heater Drain Piping

The heater drain lines from the 6th point to the 5th point heaters will experience an increase in flow velocity. However, the maximum flow velocity at EPU conditions is less than nine feet per second. Because the flow velocities at EPU conditions are low, these lines will not be instrumented.

The heater drain tank pump discharge line will experience an increase flow rate of approximately 16 percent. The maximum flow velocity of the discharge line at EPU conditions is about 22 feet per second. The two trains are symmetric. Therefore, one train will be monitored in all three (3) orthogonal directions. The monitoring location is shown in Table 5.9 below.

Table 5.9: EPU Monitoring Locations for High Pressure Heater Drain System

System	Piping Segment	Monitoring Location	Max Screening Resultant Velocity, in/sec	Description
HDH	18”-FBD-28	At El 115’-0”	0.50	Near support location N1N23G007H14 (HL-1324G)

Low Pressure Heater Drain Piping

The heater drain lines for the 1st point to the 4th point heaters will experience an increase in flow as much as 24 percent in some heaters. All three trains (A, B and C) are symmetrical in configuration. However, the flow velocities in the heater drain lines at EPU conditions are less than 7 feet per second, therefore, those lines will not be instrumented.

Moisture Separator (M/S) Drain Piping

The moisture separator drain lines will experience an increase in flow of as high as 23 percent in some heaters. However, the flow velocities in these moisture separator drain lines at EPU condition are less than 5 feet per second, therefore, those lines will not be instrumented.

5.2.3 General Discussion on Monitoring Locations

The EPU vibration monitoring locations determined for the Condensate, Extraction Steam and Heater Drain piping are summarized in tables shown above. Screening velocity criterion for the selected measurement locations is as per Non-mandatory Appendix D of the ASME O&M-S/G Part 3 (Reference 7.3).

The EPU vibration monitoring locations as shown in Table 5.2 through Table 5.6, for the MSS, FWS, Condensate, Extraction Steam, and Heater Drain piping are preferred locations for monitoring. The actual monitoring locations may be in the proximity of these preferred locations.

Piping inside containment and inaccessible piping outside containment will be monitored using accelerometers installed at selected locations on the piping and attached components. The accelerometers will be wired to remote data acquisition systems located in the Auxiliary and the Turbine buildings.

Piping outside containment that is accessible during plant operation will be monitored by performing visual observations and by taking vibration measurements using hand-held vibration instruments during power ascension to EPU conditions.

The determination of accessibilities for vibration monitoring was conducted during walk-down in the last refueling outage.

5.3 Data Acquisition and Reduction Methodology

The accelerometer and displacement data will be collected during EPU power ascension at pre-determined power levels using PC-based digital data acquisition systems (DAS's). The DAS will be located in the Auxiliary and Turbine buildings. The data set will be recorded using a minimum sample rate of 2000 samples per second per channel for a minimum duration of one minute.

Handheld instruments may also be used outside containment in accessible areas during the plant operation. Data from these instruments will be stored in DAS.

The raw time history data for each power level will be processed for comparison to applicable acceptance criteria. The data processing will include integration, determination of peak, peak-to-peak and root mean square (rms) values, and high and low pass filtering, as applicable for specific monitoring locations and acceptance criteria bases. Additional data processing, such as frequency analysis, will be performed to aid data analysis, as required.

6.0 SUMMARY

Review of previous vibration data collected during initial start-up testing as discussed in Section 3, indicates relatively low flow induced vibration levels, except a few locations during pump startup/stop transient event. Extrapolation of this earlier data to EPU power levels indicates that flow induced vibration of piping will not be adversely affected by EPU operation.

A confirmatory test program will be implemented to perform vibration monitoring during power ascension to EPU conditions. Large and small bore piping, as well as cantilevered vent and drains, on systems experiencing significant flow increases as a result of EPU will be included in the monitoring program. Piping vibration acceptance criteria is based on ASME OM-S/G Part 3.

Monitoring of inaccessible piping will be accomplished using accelerometers wired to data acquisition systems located in the Auxiliary and Turbine buildings. Accessible piping will be monitored by performing visual observations and by taking vibration measurements using hand-held vibration instruments during power ascension to EPU conditions.

7.0 REFERENCES

7.1 GE Nuclear Energy, “Constant Pressure Power Uprate”, Licensing Topical Report NEDC-33004P-A, Revision 4, Class III (Proprietary), July 2003; and NEDO-33004, Class I (Non-proprietary), July 2003.

7.2 BWR Owners’ Group EPU Committee, “Extended Power Uprate (EPU) Lessons Learned and Recommendations”, NEDO-33159 Revision 2, December 2008, BWR Owners’ Group EPU Committee.

7.3 ASME OM-S/G, “Standards and Guides for Operation and Maintenance of Nuclear Power Plants”, Part 3, 1987 Edition, Requirements for Preoperational and Initial Start-up Vibration Testing of Nuclear Power Plant Piping Systems.

7.4 “Special Test-Visual Steady-State Vibration Monitoring Program”, 1C88-ST01, June 13, 1986.