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PSEG
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10 CFR 50.90

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U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Hope Creek Generating Station
Facility Operating License No. NPF-57
NRC Docket No. 50-354

Subject: Response to Request for Additional Information
Request for License Amendment - Extended Power Uprate

Reference:
1) Letter from George P. Barnes (PSEG Nuclear LLC) to USNRC, September 18, 2006
2) Letter from USNRC to William Levis, PSEG Nuclear LLC, February 16, 2007

In Reference 1, PSEG Nuclear LLC (PSEG) requested an amendment to Facility Operating License NPF-57 and the Technical Specifications (TS) for the Hope Creek Generating Station (HCGS) to increase the maximum authorized power level to 3840 megawatts thermal (MWt).

In Reference 2, the NRC requested additional information concerning PSEG's request. Attachment 1 to this letter restates the NRC questions and provides PSEG's response to each question with the exception of questions 3.18 and 3.29. As noted in Reference 2, responses to questions 3.18 and 3.29 will be provided within 60 days from the date of Reference 2.

PSEG has determined that the information contained in this letter and attachment does not alter the conclusions reached in the 10CFR50.92 no significant hazards analysis previously submitted.

A001

There are no regulatory commitments contained within this letter

Attachment 1 contains information proprietary to General Electric Company (GE). GE requests that the proprietary information in Attachment 1 be withheld from public disclosure in accordance with 10 CFR 9.17(a)(4) and 2.390(a)(4). An affidavit supporting this request is included with Attachment 1. A non-proprietary version of the document is provided in Attachment 2.

Should you have any questions regarding this submittal, please contact Mr. Paul Duke at 856-339-1466.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 3/13/07
(date)

Sincerely,

Thomas P. Joyce
Site Vice President
Salem Generating Station

Attachments (2)

cc: S. Collins, Regional Administrator – NRC Region I
J. Shea, Project Manager - USNRC
NRC Senior Resident Inspector - Hope Creek
K. Tosch, Manager IV, NJBNE

Hope Creek Generating Station
Facility Operating License NPF-57
Docket No. 50-354

Extended Power Uprate

Response to Request for Additional Information

In Reference 1, PSEG Nuclear LLC (PSEG) requested an amendment to Facility Operating License NPF-57 and the Technical Specifications (TS) for the Hope Creek Generating Station (HCGS) to increase the maximum authorized power level to 3840 megawatts thermal (MWt).

In Reference 2, the NRC requested additional information concerning PSEG's request. With the exception of questions 3.18 and 3.29, each NRC question is restated below followed by PSEG's response. As noted in Reference 2, responses to questions 3.18 and 3.29 will be provided within 60 days from the date of Reference 2.

1) Vessels & Internals Integrity Branch (CVIB)

1.1 Section 3.2.1, "Fracture Toughness," of Attachment 4 to your submittal dated September 18, 2006, indicates that Hope Creek is participating in the Boiling Water Reactor Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (ISP), and will comply with the withdrawal schedule specified in the program, which is documented in BWRVIP-86, "Updated BWR Integrated Surveillance Program (ISP) Implementation Plan." The ISP specifies that Hope Creek shall remove the next surveillance capsule when its fluence is approximately equal to the reactor pressure vessel 1/4 thickness (1/4T) end of license (EOL) fluence. The next Hope Creek surveillance capsule is scheduled to reach this fluence and be withdrawn at 22 effective full power years (EFPY). The licensee states that the withdrawal schedule is not changed by the EPU. However, under EPU conditions, the licensee estimates that the next Hope Creek surveillance capsule will reach the unit's 1/4T EOL fluence at approximately 23 EFPY. Since BWRVIP-86, Tables 4-4 and 4-5 specify a withdrawal schedule in the year 2014 based on 22 EFPY, provide the following information.

a) Under EPU conditions, what is the projected fluence for this surveillance capsule at 23 EFPY?

<u>Response</u>
The EPU projected RPV peak neutron fluence at end-of-life at 1/4T is 7.6×10^{17} n/cm^2. Therefore the second surveillance capsule will be withdrawn at a neutron fluence of approximately 7.6×10^{17} n/cm^2.

BWRVIP-86-A was based on the non-power uprate value that capsule flux = 7.5×10^8 n/cm^2-sec

For EPU, both the RPV flux and the capsule flux were calculated using methodology in compliance with RG 1.190. The EPU analysis also determined that the pre-EPU capsule flux of 7.5×10^8 n/cm^2-sec was not accurate. The best-estimate pre-EPU capsule flux, based on the pre-EPU RPV flux of 9.3×10^8 n/cm^2-sec, is 9.4×10^8 n/cm^2-sec.

Therefore, if Hope Creek operated for12 EFPY at original power level and 3 EFPY at 1.4% uprate, then the pre-EPU fluence is 4.46×10^{17} n/cm^2. As a result, 3.14×10^{17} n/cm^2 remains for the EPU operation before the capsule is due for withdrawal.

Since EPU capsule flux = 1.28×10^9 n/cm^2-sec, the EPU operation can go on for 7.77 EFPY (at EPU power) before the capsule withdrawn. The total combined Effective Full Power Years (EFPY), with mixed definitions of full power, is 22.8 EFPY which can be rounded to 23 EFPY.

b) Explain how 23 EFPY corresponds to the BWRVIP-86 surveillance capsule withdrawal date of 2014. If 23 EFPY does not correspond to the surveillance capsule withdrawal date of 2014, then determine whether any changes to BWRVIP-86 and BWRVIP-116, "Integrated Surveillance Program (ISP) Implementation for License Renewal" are required.

Response
Once EPU is approved for Hope Creek, PSEG will inform the BWRVIP in accordance with BWRVIP ISP implementation guidelines. As stated in BWRVIP-86-A, "The ISP matrix will be re-evaluated periodically based on new information such as updated fluence evaluations, and, where changes to the matrix are warranted, they will be submitted to the NRC for approval prior to implementation." A similar statement is in BWRVIP-116. These evaluations and submittals will be made by the BWRVIP.

1.2 As addressed in Title 10 of the Code of Federal Regulations (10 CFR) Part 50, Appendix H, Section III (C)(1)(d), and in the NRC staff-approved BWRVIP ISP (BWRVIP-86), maintaining adequate contingencies to support potential changes to the program is an important part of any ISP. It should be noted that the BWRVIP considers the "standby" Hope Creek surveillance capsule to be a license renewal candidate for the ISP as documented in BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal." Therefore, the staff requests the licensee to confirm whether the third capsule (i.e., the one designated as a "standby" capsule in the Hope Creek Updated Final Safety Analysis Report (UFSAR), Section 5.3.1.6.1) will continue to reside in the reactor vessel and be tested in

accordance with BWRVIP-116 to support the ISP, and satisfy the contingency requirement of 10 CFR Part 50, Appendix H, Section III (C)(1)(d).

Response
PSEG confirms that the third surveillance capsule will continue to be designated as a "standby" capsule. This status does not change with EPU. Also this capsule remains as a license renewal candidate as described in UFSAR section 5.3.1.6.1. PSEG is committed to implementation of the BWRVIP, which includes BWRVIP-116.

1.3. Section 3.2, "Reactor Vessel," of Attachment 4 to your submittal dated September 18, 2006, states that the upper shelf energy evaluation of the reactor pressure vessel is provided in Table 3-2, "Hope Creek Upper Shelf Energy - 40 Year Life (32 EFPY)." In Table 3-2, heat 10024/1 for the LPCI nozzle forging specifies a copper content of 0.14 percent. However, in the Hope Creek UFSAR, Appendix 5A, Table 5A-6, "Heat Treatment and Chemical, Mechanical Properties of Nozzle Material," specifies a copper content of 0.15, while the NRC Reactor Vessel Integrity Database (RVID) specifies a copper content of 0.35 percent. In order for the NRC staff to verify the upper shelf energy evaluation, confirm the copper content of heat 10024/1 for the LPCI nozzle forging, and the basis for the copper content determination. Include a revised upper shelf energy evaluation, if necessary.

Response
PSEG confirms the LPCI nozzle forging, heat 10024/1, has a copper content of 0.14 percent. This value provided in the submittal is consistent with Hope Creek UFSAR, Appendix 5A, Tables 5A-5 and 5A-19. Table 5A-6 does not contain copper information. The bases for the RVID with respect to LPCI nozzles is PSE&G letter LR-N990395, dated September 1, 1999. This letter transmitted to the NRC General Electric Report GE-NE-523-A164-1294R1 for purposes of updating the RVID. Tables 7-2 and 7-3 of the report also provide a copper value of 0.14% for LPCI nozzle forging, heat 10024/1. A revised upper shelf energy evaluation is not necessary.

1.4 Section 10.7, "Plant Life," of Attachment 4 to your submittal dated September 18, 2006, identifies irradiation-assisted stress corrosion cracking (IASCC) as a degradation mechanism influenced by increases in neutron fluence. The licensee also stated that it has a procedurally controlled program that is consistent with the BWRVIP issued documents for the augmented nondestructive examination of selected reactor vessel internal components (core spray piping, core spray spargers, core shroud and core shroud supports, jet pumps and associated components, top guide, lower plenum, vessel ID (inner diameter) attachment welds, and feedwater sparger) in order to ensure their continued structural integrity. In addition, only two components, the top guide and the shroud, are predicted to exceed the BWRVIP-26 threshold fluence level of 5 x

10^{20} n/cm^2 (E > 1 MeV). This section indicates that the current inspection strategy for reactor internal components is expected to be adequate to manage any potential effects of EPU. Based on this, provide the following:

a) Confirm that the core plate, in-core flux monitoring guide tubes, and control rod guide tubes were considered in the determination of which components exceed the BWRVIP-26 threshold fluence level and become susceptible to cracking due to IASCC.

Response
The peak EPU calculated neutron fluence for the core plate is 1.79×10^{20} n/cm^2, below the IASCC threshold. The control rod and incore flux monitoring guide tubes are located below the core plate and therefore will also be below the IASCC threshold.

b) For each vessel internals component that exceeds the IASCC threshold, clarify the current inspection program to be utilized in managing IASCC of the component. Identify the scope, sample size, inspection method, frequency of examination and acceptance criteria for the inspection programs.

Response
The Hope Creek internal inspection program is based on BWRVIP issued inspection guidelines. These guidelines consider the effects of fluence on applicable components and are based on component configuration and field experience. Additionally the Hope Creek inspection program considers vendor recommendations and industry operating experience.

The following defines the inspection program for internal components that exceed the IASCC threshold:

- Shroud – The shroud inspection program is BWRVIP-76, Core Shroud Inspection and Flaw Evaluation Guidelines. This document defines the scope, sample size, inspection method, frequency of examination and flaw evaluations for the shroud. Currently the Hope Creek shroud is classified as Category B per BWRVIP-76 since no flaws were found during the last ultrasonic (UT) inspection of welds H3, H4, H5, and H7. Per BWRVIP-76 re-inspection is required in 10 years and the scope will be welds H3, H4, H5, and H7. These welds are planned to be inspected ultrasonically. The future re-inspection frequency and scope will be based on the results of the next inspection. If flaws are found during inspections, a BWRVIP-76 evaluation will be made considering crack growth rate based on fluence and fracture toughness based on fluence.

This evaluation will verify structural integrity and define inspection frequency.

- Top Guide – The top guide inspection program is BWRVIP-26-A, BWR Top Guide Inspection and Flaw Evaluation Guidelines. Hope Creek utilizes wedges to provide lateral support and to increase the seismic margin of the top guide. For this configuration, BWRVIP-26-A requires the inspection of the top guide hold down assemblies only. All hold down assemblies are visually inspected every 10 years. The grid beams, whose fluence exceeds the IASCC threshold, are not required to be inspected. BWRVIP-26-A, section 2.2.1 states, "There are no safety consequences resulting from failure at a single beam intersection. Failure of an upper beam would have no consequence, and failure of a lower beam may cause some core instrument damage but would not affect safe shutdown. Also, grid beams are intertied such that a large number of complete separations would need to occur before control rod insertion would be affected."

- In-core Flux Monitoring Dry Tube Assembly – The upper part of the dry tube assembly is located within the reactor core, adjacent to fuel assemblies. As such they are exposed to high fluence. Therefore it is assumed that the dry tubes will exceed the IASCC threshold with or without EPU. BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines, does not require inspection of in-core flux monitoring dry tube assemblies. BWRVIP-47-A, section 2.3.3 states the basis for not requiring inspection is that the failure of the dry tubes does not impair safe shutdown. The Hope Creek inspection program for dry tubes is based on GE SIL 409, revision 2. Hope Creek replaced the dry tube assemblies in 2000. The upper two feet of the dry tube assemblies will be inspected visually within 20 years of the replacement date and every two outages thereafter. The replacement dry tubes are constructed with IASCC-resistant material.

c) What BWRVIP documents are credited for these inspections? List any deviations or exceptions to these documents.

<u>Response</u>
The BWRVIP documents credited for the Hope Creek internal inspection program are listed in the response to CVIB-1.4.b above. Currently Hope Creek has no deviations or exceptions to BWRVIP inspection guidelines.

1.5 Section 10.7 of the Attachment 4 to the licensee's letter dated September 18, 2006, indicates Hope Creek injects hydrogen in the primary system for intergranular stress corrosion cracking (IGSCC) mitigation in the recirculation piping. Reactor water chemistry conditions are maintained consistent with Electric Power Research Institute (EPRI) and established industry guidelines. However, the NRC staff notes that other reactor vessel internals may be susceptible to stress corrosion cracking (SCC) and IGSCC. Therefore, what are the other water chemistry conditions, or other mitigation strategies (i.e., BWRVIP guidelines) that are used to mitigate the potential for SCC and IGSCC for the internal components?

Response
During Refueling Outage 13 (Spring 2006), Hope Creek implemented Noble Metals Chemical Addition (NMCA). This is the IGSCC mitigation strategy for the reactor internals. Hope Creek is considered a Category 3.a type plant in accordance with Table 2-6 of BWRVIP-130, BWR Water Chemistry Guidleines-2004 Revision. Currently Hope Creek complies with the recommendations of BWRVIP-130 with respect to IGSCC mitigation.

2) Electrical Engineering Branch A (EEEA)

2.1. Attachment 9 of the license amendment request states that PJM studies are documented in the Artificial [Island] Operating Guide (PSEG Engineering Evaluation A-5-500-EEE-1686). Demonstrate that this PJM study, completed in May 2003 and followed up with a facility study in February 2005, bounds the current grid conditions.

Response
As the Regional Transmission Organization (RTO), PJM administers the connection of generators to the PJM Transmission Grid. In this role, PJM coordinates the planning process for connection of new generation, coordinates the reliability studies for operation of new generation and oversees the construction of the required Interconnection Facilities. As specified in Part IV, Subpart A of the PJM Open Access Transmission Tariff (OATT), a party wishing to connect a new generation resource or increase capacity within the PJM system must submit an Interconnection Request. Salem and Hope Creek power uprates have been evaluated and are actively tracked in PJM Regional Transmission Expansion Planning Process (RTEP Process) Generation Queues H17, H18, and H19.

PJM's FERC-approved RTEP Process preserves bulk power delivery system reliability through independent analysis and recommendation, supported by broad stakeholder input and approval by an independent RTO Board in order to produce a single Regional Transmission Expansion Plan (RTE Plan). Further details of the RTEP process may be found in PJM Manual M-14-B. Since the

Salem and Hope Creek generation queues H17, H18, and H19 are being actively tracked, other changes to the transmission system have been modeled to include these generation changes. Therefore, current grid conditions are bounded by the FERC-approved PJM RTEP Process.

2.2. Describe how the Hope Creek Generating Station extended power uprate power levels have been coordinated with the Mid-Atlantic Area Reliability Council to assure that tripping of the Hope Creek Generating Station at the extended power uprate level will not cause inadequate post-trip voltages at the safety-related buses.

Response

Note that ReliabilityFirst Corporation (RFC) is the successor organization to three NERC regional reliability councils: the Mid-Atlantic Area Council, the East Central Area Coordination Agreement, and the Mid-American Interconnected Network. Hope Creek Generating Station falls within ReliabilityFirst Corporation (RFC) territory. Legacy MAAC standards are presently used by RFC.

The system impact and facility studies performed for the increases in Salem and Hope Creek generating unit capacity tested the compliance of the planned system with the MAAC Reliability Principles and Standards. The power flow portion of the analysis consisted of simulating the planned system under normal and emergency operation conditions. The transmission system was simulated under normal conditions in order to assess the transmission network element loading with the addition of any proposed upgrades. Simulations included heavy power transfer conditions followed by single and multiple transmission facility outages. Under all power flow and transient stability conditions documented in the Artificial Island Operating Guide (AIOG), the operation of Artificial Island units and supporting transmission system satisfy the MAAC Reliability Principles and Standards.

PJM has published PJM Manuals, which are the instructions, rules, procedures, and guidelines established by PJM for the operation, planning, and accounting requirements of the PJM RTO. PJM Manual 01, Control Center Requirements, Attachment B, Appendix 1, states, "In order for the nuclear power plants to be able to support their design basis, the transmission system minimum allowable voltage have been determined and provided to PJM. PJM uses these plant specific voltage requirements to ensure under all contingency cases and as part of the PJM planning process, these voltage limits are not violated."

Hope Creek has provided PJM with the minimum required 500 kV switchyard voltage in order to ensure sufficient voltage at Class 1E equipment during anticipated operating conditions and design basis accidents. This voltage requirement is reflected in design calculations and in station operating procedures.

During actual operating conditions, the PJM Energy Management System (EMS) includes a Security Analysis application that analyzes thermal, voltage, and voltage drop limit violations within the PJM. One of the contingencies analyzed by the PJM EMS is the trip of Hope Creek using the Hope Creek specific minimum switchyard post-contingency voltage limits. This process was described in Hope Creek's response to GL 2006-02 (Reference 2.2-1). This voltage limit has not changed as a result of EPU.

The same voltage limit is used in the Hope Creek load flow and motor starting calculation (E-15), the degraded grid calculation (E-15.1), the bus transfer calculation (E-15.5), and the unit trip evaluation (A-5-500-EEE-1930). These calculations and evaluation use Hope Creek distribution load data from a common load management database (A-0-ZZ-ECS-0089(01A)). Although Hope Creek EPU increases the brake horsepower requirements of the primary condensate and secondary condensate pump motors, the existing load management database already included conservative loading values that enveloped the EPU requirements. Therefore, the calculated voltage drops on the Hope Creek distribution system due to a unit trip also envelope any changes as a result of EPU.

The assurance that tripping of the Hope Creek Generating Station at the extended power uprate level will not cause inadequate post-trip voltages at the safety-related buses is provided by the PJM planning process and operating practices for maintaining adequate system voltage, the legacy MAAC standards used for maintaining a stable system, and the existing Hope Creek distribution calculations.

Reference

2.2-1 PSEG letter LR-N06-0132, Response to NRC Generic Letter 2006-02, "Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power", April 3, 2006

2.3. Describe the impact of the Hope Creek Generating Station modifications (identified in Attachment 5 of the license amendment request), both completed and planned, on the grid impact analyses. Have these modifications been coordinated with the Mid-Atlantic Area Reliability Council?

Response

The following completed and planned modifications have been included in the grid impact analysis:

1. Completed additional 500 kV circuit breaker in Hope Creek switchyard

The new 500 kV Hope Creek circuit breaker BS 2-4 (62X) was installed to provide backup clearing for circuit breaker BS 3-4 in the event of a stuck breaker. The new circuit breaker BS 2-4 was included in the grid impact study and facilities study report in accordance with MAAC Reliability Principles and Standards.

2. Completed Main Transformer replacement:

   The main transformers were replaced to allow the main generator to operate at higher output. The new transformer ratings have been incorporated into the grid impact study. The old 3-phase transformer bank was rated 1278.7 MVA, whereas the new 3-phase transformer bank is rated 1400.1 MVA.

3. Completed Low Pressure Turbine replacement:

   The turbine replacement allows Hope Creek to operate at higher real power (MW) output. The grid impact study now considers Hope Creek operating at a gross output of 1320 MW at EPU, which includes power contribution from the low-pressure turbine replacement project. Prior to EPU, the grid impact analysis only considered a main generator output of 1146 MW.

4. Planned High Pressure Turbine replacement:

   The planned high-pressure turbine replacement was also included in the grid impact analysis. The turbine replacement allows Hope Creek to operate at higher real power (MW) output. The grid impact study now considers Hope Creek operating at a gross output of 1320 MW at EPU, which includes power contribution from the high-pressure turbine replacement project. Prior to EPU, the grid impact analysis only considered a main generator output of 1146 MW.

The other completed and planned modifications identified in Attachment 5 of the license amendment request have no direct effects on grid operation and were not included in the grid impact analysis.

2.4. Describe the 'case-specific analysis' that was performed in determining that the radiation life of Target Rock Solenoid Valves inside containment could be extended up to the design life of the Hope Creek Generating Station.

<u>Response</u>
The case-specific analysis begins by subtracting the 100-day post-accident gamma dose from 90 percent of the qualified dose for the Target Rock Solenoid

Valves (TRSVs) to calculate the maximum acceptable normal operation dose to the TRSVs. This maximum acceptable normal operation dose is then converted to an equivalent life (i.e., years) by dividing this maximum normal operation dose by the expected normal operation dose rate to a TRSV. The expected normal operation dose rate is calculated for the TRSV that is in nearest proximity to normal operation radiation sources, mainly main steam and reactor coolant piping. The expected normal operation dose rate is calculated based on the actual distances between the TRSV and piping.

The large break LOCA is not considered in determining the post-accident gamma dose for the TRSVs. The TRSVs are not required to operate during a large break LOCA because depressurization of the reactor vessel occurs through the break itself. The TRSVs must only operate to depressurize the reactor vessel during a small break LOCA, or during any non-LOCA transient with a loss of offsite power. During a small break LOCA the fuel cladding integrity is not expected to fail. During non-LOCA design basis accident conditions, a failed fuel rod cladding source term involving an instantaneous release of 10% of the noble gases (except Kr-85 for which a release of 30% should be assumed) and 10% of iodine is acceptable per Regulatory Guide 1.89, Paragraph C.2.c.2 and NUREG-0588, Section 1.4.1. Therefore, relative to the LOCA scenario, no significant radiation occurs in the drywell for the TRSVs during these non-LOCA transients. For these reasons, the radiation dose chosen for qualification is conservatively assumed to be 10% of the 100-day large break LOCA gamma dose in the drywell.

Using this methodology consisting of actual separation distances and a conservative non-LOCA post-accident source term, it was determined that the TRSVs have a radiation qualified life of 38 years.

2.5. Describe the 'case-specific analysis' that was performed in determining that the radiation life of Barksdale Pressure Switches outside containment could be extended up to the design life of the Hope Creek Generating Station.

Response

The case-specific analysis for the Barksdale Pressure Switches (BPSs) is documented in Calculation H-1-ZZ-MDC-2006, Rev 0. The previous 10-year qualified life of BPSs was determined based on a normal operation dose rate of 10 R/hr. The case-specific analysis is based on the location of the BPS with respect to surrounding main steam piping in vicinity of the turbine stop valve and results in a dose rate of 3.9 R/hr, which is slightly higher the maximum expected dose rate of 3.6 R/hr (from post-HWC survey in the vicinity of the turbine stop valves), but substantially less than the dose rate of 10 R/hr used in the existing analysis to determine the qualified life of the BPSs. The BPS is required to operate for 12 hours during and following a LOCA. The maximum post-LOCA gamma and beta dose rates in the reactor building are conservatively used to

qualify the post-LOCA BPS operation for these 12 hours. Therefore, the appropriate consideration of actual distance of the worst-case BPS location from the radioactive sources and the mission time in the required post-accident condition resulted in a dose margin, which was utilized to extend the radiation qualified lives of BPSs to 27 years. For one of the four BPSs, last replaced in 1996, replacement will be required before expiration of the current operating license.

3) BWR Systems Branch (SBWB)

Fuel Storage

3.1 As shown in NRC Review Standard RS-001, BWR Template Safety Evaluation as revised for Hope Creek, Section 2.8.6, "Fuel Storage," General Design Criteria (GDC)-62 is applicable to the NRC's review of the effect of the proposed EPU on fuel storage. This GDC requires the licensee to address prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations. The NRC staff did not find any discussion on criticality of new and/or spent fuel storage in the licensee's submittals (PUSAR). Therefore, please provide this information considering the following:

a) These calculations should consider higher enrichment level, lattice exposure and the change in elements/isotopes including plutonium as a result of EPU operation.

b) In light of the fact that the void fraction history at uprated power will be appreciably higher than at current power level, clarify if the assumption made in your calculation regarding void history is consistent with the EPU conditions.

Response

The parameter that is used to assure compliance to spent fuel pool storage rack criteria is lattice k-infinity (k_∞). The limiting (i.e., maximum allowable) infinite lattice k_∞ for GNF fuel as prescribed in GESTAR-II is <1.30. This limit applies to all GE/GNF fuel products and bounds all GE/GNF spent fuel pool racks. When GE/GNF fuel is to be used with non-GE racks, GE/GNF may perform an analysis to demonstrate the acceptability of storing GNF fuel. Such an analysis has been performed for the HCGS spent fuel pool racks.

For spent fuel pool storage analysis performed by GE/GNF, the standard process is to determine a "limiting lattice" to bound the performance of the spent fuel storage unit. This "limiting" or "design basis lattice" is used to determine the maximum reactivity that is allowable in the spent fuel storage unit of interest.

The GNF 10x10 lattice that is used for this purpose is a lattice that is uniformly loaded with the maximum available enrichment and has a minimal loading of low concentration of gadolinium. The specific "GE14 design basis" lattice for the GNF Hope Creek spent fuel storage analysis was [[ ]], which bounds fuel designs for both CLTP and EPU conditions. This "design basis lattice" was depleted to determine the point of maximum in-core cold reactivity. [[ ]]. The depletion of the gadolinium is greater at lower in-channel void fractions resulting in a higher reactivity at a lower lattice exposure. This in-core cold reactivity of [[ ]] exceeds the allowable limit of GESTAR-II by more than [[ ]]Δk providing additional conservatism to the analysis.

This depleted "design basis lattice" with its associated fuel isotopic inventory is placed in the spent fuel pool storage unit to determine the acceptability of this design in the spent fuel pool storage rack of interest. The reactivity of the "design basis lattice" in the spent fuel storage rack must not exceed a k_∞ of 0.95.

By use of a limiting "design basis lattice" at peak reactivity, the possibility of a full core off-load at peak lattice reactivity is accommodated without special analysis and the complete range of potential lattice designs and operational strategies are shown to be acceptable. As a result of the characteristic of gadolinium to deplete most rapidly in a low in-channel void condition, the effects of EPU/MELLLA operation do not impact the maximum cold lattice reactivity.

In the normal process of finalizing all bundle designs, the maximum in-core lattice k_∞ in the bundle (plus an additional 0.01 for uncertainties) is checked against the maximum allowable GESTAR-II value of 1.30. The hot and cold state points are analyzed, void points of 0, 40, and 70% void history are analyzed, and all exposures are analyzed. If the maximum cold in-core k_∞ in the design bundle (s) is less than 1.29, then the bundle (s) can be placed in any GE/GNF analyzed spent fuel storage rack. If the bundle fails to meet the limiting 1.29 lattice k_∞ criteria, the bundle verification cannot be completed, and the manufacturing of the bundle cannot begin until the issue is resolved.

This process applies to all GE/GNF bundle designs, and is independent of power uprate conditions.

Analyses have also been performed for the legacy SVEA fuel, demonstrating the acceptability of storing SVEA fuel in the HCGS spent fuel pool racks. Since no new SVEA fuel will be introduced for EPU, and the remaining SVEA fuel in the reactor core is operating at exposure values significantly past the point of peak

reactivity, EPU operation will not adversely impact the existing spent fuel criticality analysis for SVEA fuel.

3.2 Question removed for Revision.

3.3 In the Hope Creek PUSAR Table 6-3 (Spent Fuel Pool Parameters) indicates a very small margin in temperature limits for batch offload. It is stated that the 135°F limit was selected to assure operator comfort and to provide ample margin against inventory loss due to evaporation or boiling. What measures are planned to remain below this limit?

Response
The values tabulated in Table 6-3 are results of a conservative analysis of the SFP temperature following a post-EPU batch refueling with a postulated loss of the RHR FPC assist mode. The purpose of the analysis was to determine the delay required under design basis conditions (95°F Safety Auxiliary Cooling System (SACS) temperature) before fuel movement could begin while maintaining SFP temperature less than 135°F.

The results demonstrate the cooling capabilities achievable with the designated conditions but are not representative of the typical plant configuration that exists prior to scheduled refueling outages. In this scenario, SFP cooling is provided by both trains of the Fuel Pool Cooling and Cleanup system (FPCC) in service. The analysis determined the maximum heat load that can be removed solely by FPCC with the SFP at 134.9°F and SACS at the 95°F maximum design limit. The calculated maximum heat load is used to determine the decay heat that can be added to the SFP under these conditions. In this analysis, the initial decay heat load in the SFP prior to the batch offload is based on 13 previous refuelings that placed 3010 bundles in the SFP, resulting in 5.14 MBtu/hr. The initial SFP temperature is calculated to be 107°F. The additional decay heat from the batch offload that can be added to the SFP and stay below 135°F with these conditions is calculated to be 13.57 MBtu/hr. The batch refueling adds 232 fuel bundles (1/3 core) to the SFP at an assumed rate of 6 fuel bundles per hour moved from the RPV and placed into the SFP. The 13.57 MBtu/hr decay heat load will not be exceeded if the batch offload begins 59 hours after reactor shutdown and takes 39 hours to complete (98 hours after shutdown). The actual temperature peak occurs 17 hours later (at 115 hours after reactor shutdown).

Hope Creek refueling outages are planned when many of the parameters used to determine Table 6-3 values are significantly improved. Refueling outages are scheduled in the Spring or Fall when SACS (and SW) cooling water temperature is substantially lower than the design limit used in the analysis. The outage planning process includes Administrative procedures that require actual plant conditions (i.e. SW, SACS and SFP water temperatures) to be used in determining available heat removal capacity prior to plant shutdown. Calculation

EC-0074 is updated prior to each refueling outage to determine heat-up rates for the SFP and Reactor vessel. The results of EC-0074 provide a planning tool for Outage Management and Operations to plan fuel moves to ensure SFP temperatures are manageable, and develop contingent planning in the event that a pump and/or heat exchanger is lost. In addition, the outage planning process ensures that required equipment is available and operable prior to plant shutdown, all administrative limits are satisfied (i.e. allowable SFP temperature) and defense in depth is provided against strategic equipment failure before additional fuel is moved into the SFP. Therefore, the actual cooling capability available during a typical scheduled refueling is substantially greater than the results set forth in the Table 6-3.

Core

3.4 Please provide the following information applicable to Cycle 15 (first EPU operation):

a) The average bundle power before and after the EPU.

b) The peak bundle power before and after the EPU.

c) Which fuel type (GE14 or SVEA-96+) will be limiting with respect to the thermal limits, safety limit for minimum critical power ratio (SLMCPR), operating limit maximum critical power ratio (OLMCPR), linear heat generation rate (LHGR), maximum average planar linear heat-generation rate (MAPLHGR), and peak cladding temperature (PCT) for Cycle 15?

Response

The average bundle power is the total core thermal power divided by the number of fuel assemblies (764). At the current licensed thermal power (3339 MWt), the average bundle power is 4.37 MWt. At the EPU thermal power (3840 MWt), the average bundle power is 5.03 MWt. However, Cycle 15 will be designed to a maximum power level of 3722 MWt, which corresponds to an average bundle power of 4.87 MWt.

The peak bundle power, before and after EPU, as a function of cycle exposure is presented in Figure 2.1 of GNF report 0000-0031-9433-IMLTR-SUP1, Rev. 0, "Interim Methods LTR Supplement for Hope Creek Extended Power Uprate." The maximum pre- and post-EPU peak bundle powers are approximately 6.8 and 7.1 MWt, respectively. This represents an increase of approximately 5%, which is less than the EPU core power increase of 15%. The reason for this difference is that high power bundles are constrained by the fuel thermal limits. In particular, the fuel thermal mechanical limits or OLMCPR limits effectively constrain the maximum achievable bundle power. The fuel thermal limits are associated with the fuel and core designs, and are not a direct function of EPU.

The actual Cycle 15 licensing basis core design is not yet complete. However, it is expected that the peak bundle power will be somewhat less than 7.1 MWt based on the maximum core design power level of 3722 MWt.

The GNF SLMCPR methodology determines a single core dependent value as opposed to a value for each bundle type within a core. The SVEA fuel operating in the Cycle 15 core will be high exposure, low reactivity fuel in its fourth or fifth operating cycle. Therefore, only GNF fuel bundles are expected to contribute in the SLMCPR evaluation. The peak bundle power of the SVEA fuel at EPU conditions, as a function of cycle exposure, is presented in Figure 2.1 of GNF report 0000-0031-9433-IMLTR-SUP1, Rev. 0. The SVEA peak bundle power is significantly lower than that of the limiting GE14 fuel. Based on this lower power, the results of the Cycle 15 EPU core design in this report demonstrate that the GE14 fuel is limiting for MCPR and MAPLHGR (which protects PCT) for the entire operating cycle. The GE14 fuel is also limiting for LHGR for the majority of the operating cycle, except for a brief exposure interval near the end of the cycle. This exception occurs during a period when the GE14 LHGR is relatively low, and significant margin exists to the LHGR limit. The actual Cycle 15 licensing basis core design is not yet complete. However, it is expected that the thermal limit performance results will be similar, with the GE14 fuel the limiting fuel type with respect to thermal limits.

LOCA

3.5 Question removed for Revision.

3.6 Question Deleted.

3.7 Please discuss the impact of increased discharge piping water leg height and temperature on [safety relief valve] SRV operation for EPU (flow and response time characteristics) as a result of the higher expected suppression pool temperature and containment pressure during a postulated LOCA and anticipated transient without scram (ATWS).

Response
SRV Performance Considerations:
The maximum SRV backpressure limit for Hope Creek is 540 psia, based on a backpressure limit for these SRVs of 40% of the maximum inlet pressure of 1355 psia at an SRV flow rate of 1,035,000 lb/hr. The backpressure limit of 40% applies both during steady-state operation and during the discharge line water clearing (valve opening) transient. Back pressure greater than 40% of the inlet pressure will hinder flow through the SRV. The backpressure requirement applies equally to ADS and non-ADS valves. The pre-EPU peak valve opening transient and steady-state back pressures calculated for Hope Creek are 520.8

psia and 490.3 psia, respectively. Also, the design temperature of the SRV discharge line is 490°F

Impact of Elevated Containment Pressure on the SRV Discharge Line (SRVDL) Water Leg Height Prior to SRV Actuation
When an SRV opens, the following occurs in the SRVDL:

1. The water leg from the SRVDL and quencher is expelled;
2. The nitrogen in the SRVDL is expelled; and
3. The steam from the RPV is expelled.

When the SRV closes, the steam in the SRVDL condenses, which rapidly depressurizes the SRVDL and causes the water leg in the SRVDL to begin rising. The vacuum breaker (VB) located on the SRVDL opens when the pressure differential between the drywell (DW) and the SRVDL reaches approximately 0.5 psi and rapidly restores the SRVDL pressure to within 0.5 psi less than the DW pressure. This essentially restores the water leg to the level before SRV opening.

Similarly, there are VBs installed between the DW and the wetwell (WW). The purpose is to ensure that the negative differential pressures between the DW and the WW do not exceed design values. The VBs open when the WW pressure is more than 0.2 psi higher than the DW pressure. Therefore, since the SRVDL pressure will be within 0.5 psi of the drywell pressure, and the DW pressure will be within 0.2 psi of the wetwell pressure, the total differential pressure between the WW and the SRVDL will be no higher than 1 psi.

SBLOCA Response
During the initial phase of the SBLOCA, break flow into the DW causes the DW pressure to increase to higher than the WW pressure by the pressure difference corresponding to the downcomer submergence of the DW to WW vent system (typically 1.5 psi). Operation of the VBs between the DW and the SRVDLs will ensure that the SRVDL pressure is no lower than approximately 0.5 psi below the DW pressure. Therefore, the pressure inside the SRVDL prior to SRV actuation will be at least 1 psi greater than the WW pressure. This means that the water leg in the SRVDL will be depressed by a static head corresponding to 1 psi and the SRVDL will actually have a smaller water leg than under normal conditions.

After this initial phase, the operator is expected to turn on the containment sprays (as directed by plant procedures), in order to depressurize the DW and the WW. As a result, it is possible to create a condition where the DW pressure is less than the WW pressure. If the pressure differential between the WW and the DW is greater than 0.2 psi, the WW to DW VBs would open and maintain this DW to WW pressure differential. Operation of the DW to SRVDL VBs (with a VB

setpoint of 0.5 psid) would maintain the SRVDL pressure, prior to an SRV actuation, to within 0.5 psi of the drywell pressure. As a result, the differential pressure between the SRVDL and the WW gas space would be no more than 1 psi for SBLOCA conditions with elevated containment pressure, which would have a minimal impact on water leg height.

Other Events:
For non-LOCA events (e.g., ATWS) where SRV actuation occurs, steam flow will cause heat up of the suppression pool (SP) and consequently, heat up and pressurization of the WW gas space due to evaporation from the SP and due to direct heating from the SP surface; it is possible to have WW pressures higher than the DW pressure. However, operation of the WW to DW VBs would maintain this difference to within 0.2 psid. Operation of the DW to SRVDL VBs would maintain the SRVDL pressure to within 0.5 psi of the DW pressure. Therefore, the pressure differential between the WW and the SRVDL prior to SRV actuation will be on the order of 1 psi.

Conclusion – Elevated Containment Pressure:
Therefore, there will be minimal impact from elevated containment pressure during an SBLOCA or non-LOCA event on the SRVDL water leg height prior to SRV actuations.

Conclusion - Impact of Elevated Containment Pressure on SRV Capacity:
The SRV capacity calculations assume choked flow conditions, which are independent of the SRV line backpressure. This assumption is true as long as the SRVDL backpressure does not increase significantly. As discussed above, since the change in backpressure is on the order of 1 psi, there will be minimal impact of elevated containment pressure on the SRVDL water leg height prior to SRV actuations. Therefore, SRV capacity will not be affected.

The discussion above focuses on SRV flow rate immediately following SRV opening when the effects of water leg can potentially affect the SRVDL backpressure and therefore the SRV flow. Once the SRVDL water leg clears, which happens in a very short time period, steady steam flow through the quencher reduces the SRVDL backpressure.

SRV Performance Considerations:
The maximum SRV backpressure limit for Hope Creek is 540 psia, based on a backpressure limit for these SRVs of 40% of the maximum inlet pressure of 1355 psia at an SRV flow rate of 1,035,000 lb/hr. The backpressure limit of 40% applies both during steady-state operation and during the discharge line water clearing (valve opening) transient. Back pressure greater than 40% of the inlet pressure will hinder flow through the SRV. The backpressure requirement applies equally to ADS and non-ADS valves. The pre-EPU peak valve opening transient and steady-state back pressures calculated for Hope Creek are 520.8

psia and 490.3 psia, respectively. An increase of 1 or 2 psi due to water leg height changes for EPU will not increase these backpressure values above the design limit of 540 psia. Thus, the post-EPU backpressure will remain below the design limit of 540 psia.

The SRV discharge line design temperature of 490°F bounds the maximum EPU suppression pool temperature of 212.3°F.

The response time characteristics of the SRVs are ≤ 0.4 seconds delay between trip and motion, and ≤ 0.1 seconds response (main disc stroke time). The SRV must first open to allow steam into the discharge pipe before the pipe will develop a backpressure on the valve. The SRV response time characteristics are thus independent of the discharge line backpressure. Therefore, the SRV response time characteristics are not affected by any increase in discharge piping water leg height for EPU.

3.8 Question removed for Revision after the GE Interim Methods (NEDC-33173P) draft SE is completed.

3.9 Question Deleted.

Functional Design of Control Rod Drive System

3.10 In a letter dated July 14, 2005 (ADAMS Accession No. ML052000328), GE recommended a surveillance program for monitoring Channel-Control Blade Interference for BWR/2-5 (C/D-Lattice) plants. HC was among the plants recommended for the surveillance program. HC-PUSAR does not address Channel-Control Blade Interference at constant-pressure power uprate (CPPU) conditions. Please discuss the affects of Channel-Control Blade Interference at CPPU conditions and whether the recommended GE surveillance program has been implemented. GE has indicated that channel bow evaluation will be eventually implemented in all reload core designs. Has the channel bow evaluation been included in the EPU reload core design?

Response
HCGS is currently following the guidance of SIL 320, Rev. 3. HCGS has not previously implemented the recommended GE surveillance program. The GE surveillance program was not implemented due to several factors including; 1) the SVEA fuel in operation at the time of the July 14, 2005 GE letter was not impacted by the GE channel-control blade interference issue, 2) HCGS was not controlling fresh GE14 fuel and was operating with 18-month fuel cycles, and 3) the existing GE14 fuel was not operating at the susceptible exposure values. However, HCGS will be implementing the GE surveillance program recommendations as GE14 fuel in the core approaches the susceptible exposure values. Channel bow is being evaluated as part of the Cycle 15 EPU reload

design. While bow is driven by flux/fluence, which increase with power uprate, the uprated core conditions are within the current fleet experience base.

3.11 In Section 4.6.1.2.4.1, Hydraulic Requirements, the Hope Creek UFSAR states that a drive pressure of 260 psi (minimum) above reactor vessel pressure is required for a flow rate of approximately 4 gpm to insert and 2 gpm to withdraw a control rod. The generic evaluation in ELTR- 2 states "Normal CRD header pressure is maintained approximately 250 psig above the lower head pressure." Please address whether the drive pressure difference has an affect on the insert/withdraw drive flows.

Response
The generic ELTR-2 statement of approximately 250 psid was not used to relax the specific HCGS FSAR requirement for 260 psid (minimum). Rather, it was determined that the sole EPU impact on CRD cooling and positioning flow was an increase of approximately 1 psi in the CRD hydraulic system required discharge pressure. The differential pressure between the drive water header and the RPV is set by a manual pressure control valve which will establish the pressure that gives the flow rate of approximately 4 gpm to insert and 2 gpm to withdraw a control rod. The CRD System pressure and flow capability can easily handle the 1 psi increase in pressure above the core plate at EPU. For example, the charging header pressure is approximately 1500 psig and the flow control valves, downstream of the drive water pumps are only approximately 50% open at CLTP.

Standby Liquid Control System

3.12 In the Hope Creek PUSAR, Section 9.3.1, Anticipated Transients Without Scram, it states that Hope Creek meets the ATWS mitigation requirements defined in 10 CFR 50.62 for boron injection equivalent to 86 gpm. Please provide the calculations that demonstrate the 86 gpm equivalency requirement of the rule satisfies the following relationship:

$$(Q/86) \times (M251/M) \times C/13) \times (E/19.8) > 1$$

where:

Q = expected standby liquid control system (SLCS) flow rate (gpm)

M = mass of water in the reactor vessel and recirculation system at hot rated condition in lbs

C = sodium pentaborate solution concentration (weight percent)

E = Boron-10 isotope enrichment (19.8% of natural boron)

M251 = mass of water in a BWR/4 251 inches diam. reactor vessel (lbs) = 628,300 lbs

Response
For HCGS, the sodium pentaborate solution concentration, C, is 13.6 weight percent, the Boron-10 isotope enrichment, E, is 19.8% (natural boron), the expected SLCS flow rate, Q, is 82.4 gpm, and HCGS is a BWR4 251-inch plant, so M = 628,300 lbs. Therefore, the 86-gpm equivalency requirement is satisfied as follows:

$$(Q/86) \times (M251/M) \times (C/13) \times (E/19.8) > 1$$

$$(82.4/86) \times (628{,}300/628{,}300) \times (13.6/13) \times (19.8/19.8) = 1.002 > 1$$

3.13 The licensee performed a plant-specific ATWS analysis and found that the peak calculated vessel pressure during SLCS operation is 1179 psig. Please provide the results including the maximum pump discharge pressure and operating pressure margin for the SLCS pump discharge relief valves.

Response
The 14 Hope Creek SRVs are set at staggered relief pressures of 1108 psig (4 valves), 1120 psig (5 valves) and 1130 psig (5 valves). In the ATWS analysis, it is assumed that at least one 1130 psig SRV opens during the SLCS injection period. This valve lifts at the high-end (3%) of the set-point range (i.e. 1130 psi x 1.03 + 14.7 = 1179 psia (1165 psig)).

The SLCS pump discharge relief valves are set at 1400 psig.

SLCS is designed to automatically initiate in an ATWS after a 230 second time delay as the RPV is depressurized by the SRVs. Operators may manually initiate SLCS prior to the automatic start at 230 seconds. Two scenarios are evaluated for conservatively determining the SLCS pressure response during the postulated ATWS:

1. SLCS initiation at 230 seconds
2. SLCS initiation before 230 seconds.

SLCS initiation at 230 seconds
After 230 seconds, the maximum calculated SLCS pump discharge pressure is 1259 psig.

SLCS Relief Valve Setpoint Margin

SLC Relief Valve Set-Point	1400 psig

Maximum calculated SLCS Pump Discharge Pressure during ATWS (after 230 sec)	1259 psig
Pressure below relief valve setpoint	141 psig
Minimum Required Pressure below setpoint	75 psig
Available Operating Margin	66 psig

SLCS initiation before 230 seconds

On an ATWS initiation signal, the initial RPV pressure peak would exceed the SLCS pump discharge relief valve set-point of 1400 psig for certain limiting ATWS events (such as pressure-regulator failed open (PRFO) and MSIV closure). RPV pressure peaks at 1437 psig during the limiting PRFO event at 27.8 seconds into the event. Assuming SLCS was in service, this would correspond to a SLCS pump discharge pressure of approximately 1530 psig, lifting the SLCS pressure relief valve.

The discharge from the relief valve re-circulates back to the SLCS pump suction line until the relief valve re-seats. The core response to SLCS is evaluated at time =230 seconds and no credit is taken for SLCS addition prior to 230 seconds. Therefore, SLCS discharge may re-circulate without an adverse impact, provided pump discharge pressure reduces sufficiently to allow the relief valve to re-seat prior to 230 seconds. In this scenario, the critical parameter is pressure at time = 230 seconds regardless of when the SLCS pump was started. The results of this scenario are tabulated below:

Relief Valve Reset Margin

RPV Pressure at 230 Seconds	1067 psig
Pump Discharge Pressure	1162 psig
Relief Valve Reset Point	1260 psig
Reset Available	98 psid
Required Minimum Reset	25 psid
Reset margin	73 psid

The relief valve will reset prior to the end of the 230 seconds.

A PSEG calculation (BH-0003, Revision 3) shows that the lower two banks of SRVs are sufficient to pass the post-ATWS steam flow during the SLCS injection period. Consequently, actual peak pressures during the SLCS injection period will be lower and the maximum expected SLCS pump discharge pressure will also be lower, thereby further increasing the above margins.

3.14 Question Deleted.

3.15 In the Hope Creek PUSAR Sections 10.5.3 and 10.5.4.1 discuss the automatic initiation of the Standby Liquid Control System design feature at Hope Creek.

Section 9.3.5.1 of the Hope Creek UFSAR describes the automatic actuation of a timer upon receipt of a signal from the Redundant Reactivity Control System (RRCS). Please confirm that the current timer setting is still valid for EPU.

Response
The analysis of the Anticipated Transient Without Scram (ATWS) event described in PUSAR Section 9.3.1 credits the automatic initiation of the Standby Liquid Control System as a mitigating action. The ATWS analysis includes the effect of the time delay from the subject timer after the Redundant Reactivity Control System (RRCS) initiation signal. As documented in PUSAR Section 9.3.1, the ATWS event analysis results meet all acceptance criteria. Therefore, the ATWS analysis results demonstrate that the current timer setting remains valid for EPU.

Residual Heat Removal (RHR) System

3.16 Following abnormal events, the [suppression pool cooling] (SPC) function controls the long-term suppression pool temperature such that the maximum operating temperature limit is not exceeded. The proposed EPU would increase the reactor decay heat, which increases the heat input to the suppression pool during a LOCA, and results in a higher peak suppression pool temperature. Please address the SPC function to control the long-term suppression pool temperature and provide the results that demonstrate that the maximum operating temperature limit is not exceeded.

Response
The large break LOCA bounds the suppression pool response of the small break LOCA. The most limiting design basis LOCA case for the suppression pool is identified in the UFSAR as Case "C": LBLOCA + LOP. No offsite power is available following the instantaneous guillotine break of the RCS recirculation suction line and a corresponding single failure of the "A" EDG is postulated. After 10 minutes of LPCI operation with (3) RHR pumps, operator action manually aligns one RHR pump and one RHR heat exchanger to cool the LPCI discharge before injecting into the RPV. During the design basis case for a LOP only, operators align RHR to suppression pool cooling 15 minutes into the event.

EPU results in a maximum suppression pool temperature of 212.3°F, approximately 8.4 hours after the LOCA + LOP. The LOP only event results in a maximum suppression pool temperature of 213.6°F, approximately 9.1 hours after the LOP. Both events result in suppression pool temperatures slightly above the current licensing bases temperature of 212°F. Analysis of the LOP is based on rapidly depressurizing the RPV using manual SRV blow-down to determine the bounding containment response at the maximum allowable 100°F per hour. The anticipated operator response to depressurize the RPV following a LOP is expected to take longer. For example, calculation BC-0052, Revision 3,

shows a post-CPPU LOP cool-down with only one RHR heat exchanger in suppression pool cooling (following a postulated Appendix R fire), which determines a peak pool temperature of 206.9°F. Therefore, the bounding suppression pool temperature is the result of the large break LOCA. The SPC function of RHR remains essentially unchanged by the 0.3°F increase in suppression pool temperature following CPPU.

ECCS pump NPSH has been evaluated with suppression pool temperatures as high as 218°F and has been shown to be adequate at that temperature with no credit for containment overpressure. Hence ECCS operations are not adversely affected at 212.3°F.

3.17 What is the available RHR Heat Exchanger margin with the increased decay heat load due to EPU?

Response
The assumed RHR heat exchanger performance is based on a heat exchanger efficiency (K-value) of 307 Btu/sec-°F. This is the same K-value that was derived for the RHR heat exchanger when maximum SACS temperature was increased to 100°F and is used in the current HCGS containment response analysis (GE-NE-T2300759-00-02). The K-value is not changed for CPPU. The K-value of 307 Btu/sec-°F was reviewed and discussed in the safety analysis report (SER) for Amendment 120 dated 4/19/1999. In this SER, the staff found that use of the GE SHEX code to establish the heat exchanger K-value to be acceptable. As noted in the Amendment 120 SER, the K-value was determined in a maximum fouled condition.

RHR heat exchanger loads change due to EPU during design basis accident conditions (LOCA and LOP) due to increased predicted suppression pool temperatures. The post-LOCA pool temperature increases to 212.3°F and post-LOP to 213.6°F assuming operation at a rated thermal power (RTP) of 3840 MWt. The RHR heat load during a LOCA increases from 121.7 (CLTP) to 127.1 MBtu/hr for EPU. The 127.1 Mbtu/hr value was derived from a maximum suppression pool temperature of 215.6°F based on an assumed RTP of 102% of 3952 MWt. Therefore, the actual RHR heat exchanger heat load would be less at 3840 MWt. Consequently, heat exchanger margins exist in both the assumed heat exchanger fouling during the derivation of the K-value and also in the LOCA analysis that was performed at an RTP of 102% of 3952 MWt rather than 3840 MWt.

Transients and Accidents

3.19 As discussed in a November meeting, please provide a reference roadmap to the licensing topical reports (ELTR1, ELTR2, CLTR), PUSAR section or UFSAR for

the analyzed transients according to the order in Review Standard for EPU (RS 001) Section 2.8.5.

Response
The following provides a reference roadmap for RS-001, Section 2.8.5.

2.8.5 Accident and Transient Analyses

2.8.5.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Main Steam Relief or Safety Valve

These excessive heat removal events are addressed in ELTR1, Section 5.3.2, and Appendix E, Table E-1; A. Fuel Thermal Margin Events; Items 3 (FW Controller Failure-Max. Demand (Increase in FW Flow)), 5, (Loss of FW Heater (Decrease in FW Temperature)). Hope Creek specific results are provided in PUSAR Section 9.1.1 and Table 9-2.

Note that the Increase in Steam Flow event ([[

]] within the reload evaluation scope of GESTAR II.

The Inadvertent Opening of a Safety Relief Valve event is [[
]]

2.8.5.2 Decrease in Heat Removal by the Secondary System

2.8.5.2.1 Loss of External Load; Turbine Trip; Loss of Condenser Vacuum; Closure of Main Steam Isolation Valve; and Steam Pressure Regulator Failure (Closed)

These pressurization events are addressed in ELTR1, Sections 5.3.2 and 5.5.1.4, and Appendix E, Table E-1:

A. Fuel Thermal Margin Events
   1. Generator Load Rejection with Bypass Failure
   2. Turbine Trip with Bypass Failure
   4. Pressure Regulator Downscale Failure
   10. Generator Load Rejection
   11. Main Steam Isolation Valve Closure, One Valve and All Valves

B. Limiting Transient Overpressure Events
   12. Main Steam Isolation Valve Closure with Scram on High Flux (Failure of Direct Scram)

13. Turbine Trip, Bypass Failure, with Scram on High Flux (Failure of Direct Scram)

The Hope Creek specific results for Fuel Thermal Margin Events are provided in PUSAR Section 9.1 and Table 9-2. The Hope Creek specific results for Limiting Transient Overpressure Events are provided in PUSAR Section 3.1 and Figure 3-1.

Note that the Loss of Condenser Vacuum event is [[

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2.8.5.2.2 Loss of Non-emergency AC Power to the Station Auxiliaries

As stated in RS-001, "The loss of non-emergency ac power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant circulation pumps. This causes a flow coastdown as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip."

The Loss of Non-Emergency AC Power to the Station Auxiliaries event is [[

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2.8.5.2.3 Loss of Normal Feedwater Flow

These Loss of Normal Feedwater Flow is addressed in ELTR1, Section 5.3.2, and Appendix E, Table E-1; C. Limiting Loss of Water Level Transient Events; Items 14 (Loss of Feedwater Flow)) and ELTR2, Section 3.1. The Hope Creek specific results are provided in PUSAR Section 9.1.1 and Table 9-2.

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

The Loss of Forced Reactor Coolant Flow is addressed in ELTR1, Section 5.3.2, Category 3.

The Loss of Forced Reactor Coolant Flow Including Trip of Pump Motor and Flow Controller Malfunctions events are events that result in a decrease in reactor core coolant flow rate. Events in this category are [[

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

The Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break are addressed in ELTR1, Section 5.3.2, Category 3.

The Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break events are events that result in a decrease in reactor core coolant flow rate. [[

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2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition

The Rod Worth Minimizer (RWM) controls this event and the RWM is addressed in the CLTR, Sections 5.1.2 and 5.3.4 and in PUSAR Sections 5.1.2 and 5.3.4.

2.8.5.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power

The Rod Block Monitor (RBM) controls this event. The RBM setpoints are developed as a function of core power and flow is addressed in the CLTR, Section 5.3.5 and in PUSAR Section 5.3.5. The RBM rod block is no longer credited in the evaluation of the control rod withdrawal error as described in Section 4.0 of "Hope Creek Generating Station APRM / RBM /

Technical Specifications / Maximum Extended Load Line Limit Analysis (ARTS / MELLLA)," NEDC-33066P, Revision 2, February 2005.

2.8.5.4.3 Startup of a Recirculation Loop at an Incorrect Temperature and Flow Controller Malfunction Causing an Increase in Core Flow Rate

The startup of a recirculation loop at an incorrect temperature and flow controller malfunction causing an increase in core flow rate events are addressed in ELTR1 Section 5.3.2, Table E-1, Items 8 and 9. The Hope Creek specific results are provided in PUSAR Section 9.1 and Table 9-2.

2.8.5.4.4 Spectrum of Rod Drop Accidents

This event is evaluated for each reload core and the results of that evaluation are reported in the cycle specific Supplemental Reload Licensing Report (SRLR) per GESTAR II, NEDE-24011-P-A-US, Section 2.2.3.1. This event is controlled by the Rod Worth Minimizer (RWM) and the RWM is addressed in the CLTR, Sections 5.1.2 and 5.3.4 and in PUSAR Sections 5.1.2 and 5.3.4. The consequences of a CRDA are addressed in CLTR Section 9.2 and the Hope Creek specific results are provided in PUSAR Section 9.2 and Table 9-7.

2.8.5.5 Inadvertent Operation of ECCS or Malfunction that Increases Reactor Coolant Inventory

The increased reactor coolant inventory event are addressed in ELTR1, Section 5.3.2, and Appendix E, Table E-1; A. Fuel Thermal Margin Events; Items 6 (Inadvertent HPCI Start) and 3 (FW Controller Failure-Max. Demand (Increase in FW Flow, which is bounding)). The Hope Creek specific results are provided in PUSAR Section 9.1.1 and Table 9-2 for the FW Controller Failure-Max. Demand event.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of a Pressure Relief Valve

ELTR1 Section 5.3.2 states that the bounding event for inventory loss is the loss of FW flow event. The Hope Creek specific results are provided in PUSAR Section 9.1 and confirm the non-limiting status for Hope Creek.

The Inadvertent Opening of a Safety Valve event is [[

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

The ECCS hardware evaluations are not specifically addressed in RS-001 but have been included in this RS Topic. The sections are:

HPCI	ELTR1	5.6.7	LPCI	ELTR1	5.6.4
	CLTR	4.2.1		CLTR	4.2.4
	PUSAR	4.2.1		PUSAR	4.2.4
Core Spray	ELTR2	3.3	ADS	ELTR1	5.6.8
	CLTR	4.2.3		CLTR	4.2.5
	PUSAR	4.2.3		PUSAR	4.2.5

The ECCS-LOCA performance is evaluated based on ELTR1, Section 5.3.1, and ELTR1 Appendix D. The Hope Creek specific results are provided in PUSAR Section 4.3 and Table 4-2.

2.8.5.7 Anticipated Transients Without Scrams

ELTR1	5.3.4 and Appendix L
ELTR2	3.7
PUSAR	9.3.1, Tables 9-8 and 9-9

3.20 In the Hope Creek PUSAR Table 1-3, the core inlet enthalpy is lower in CPPU than in current limiting thermal power (CLTP) condition. Please explain why core inlet enthalpy is lower when feedwater temperature is higher in constant pressure power uprate operation. In the table on page 3-15 of PUSAR, loop flow (17.35 Mlbm/hr) at CPPU is higher than it is in CLTP (16.76 Mlbm/hr) at 100% core flow case (same for CLTP and CPPU). Please explain how jet pumps induce less suction flow with increased jet flow.

<u>Response</u>
<u>Enthalpy</u>
An increase in feedwater temperature (enthalpy) will generally result in an increase in core inlet enthalpy, all other heat balance parameters being the same. However, EPU conditions result in a significant (~16.5%) increase in steam flow and feedwater flow. Therefore, for a given total core flow (e.g., 100%

rated flow), the amount of feedwater flow as a fraction of total core flow (recirculating coolant flow + feedwater flow) increases. More of the core flow is converted to steam for EPU and therefore, less circulated saturated water from the separators is mixing with more subcooled feedwater. While the increased feedwater temperature tends to increase core inlet enthalpy, the combination of increased feedwater flow with less circulated saturated flow tends to decrease core inlet enthalpy since the feedwater temperature is lower than the temperature of the recirculating coolant flow. This effect is enough to offset the increase in feedwater temperature, and the resulting core inlet enthalpy is slightly lower for CPPU conditions.

Jet Pump
The ratio of the jet pump induced (suction) flow to drive (recirculation) flow is known as the jet pump m-ratio. The jet pump m-ratio varies with the overall resistance of the recirculation loop (e.g., at lower core pressure drop conditions the m-ratio increases, at higher core pressure drop conditions the m-ratio decreases). Given this jet pump characteristic, higher drive flow is required to overcome higher resistance. At CPPU conditions, for a given total core flow (e.g., 100% rated flow), the core pressure drop is higher (due to higher core void content), resulting in a lower jet pump m-ratio. This then results in a higher jet pump drive flow for the same total core flow.

3.21 The Hope Creek PUSAR does not reference CLTP as the basis for areas involving reactor systems and fuel issues. The transients analyzed in Table 9-2 and Figures 9-1 to 9-4 are not complete compared to Table E-1 in ELTR-1, which is the minimum set of transients suggested by GE. Please provide the rationale for the missing ones, i.e.,

No 4 Pressure Regulator Downscale Failure
No 6 Inadvertent HPCI (high-pressure coolant injection) start
No 13 Turbine trip, bypass failure, with scram on High Flux.

Response
The Pressure Regulator Downscale Failure is listed as item 4 in Table E-1. However, as described in ELTR1, Section 5.3.2, the Pressure Regulator Downscale Failure was included in the list for BWR/6 plants where the SAR and reload evaluations include the downscale failure of both pressure regulators. As Hope Creek is not a BWR/6, this event is not applicable and is therefore not evaluated.

The Inadvertent HPCI Start is listed as item 6 in Table E-1. Table E-1 clarifies that this event is evaluated only if it is not bounded by Loss of Feedwater Heater event. The Inadvertent HPCI Start results in an increase in core inlet subcooling, similar to the Loss of Feedwater Heater, without any other key system actuations during the transient. Calculations performed for Hope Creek reload licensing

confirm that the Loss of Feedwater Heater event bounds the HPCI event when modeled in this fashion. For EPU, the HPCI flow is unchanged and as a result is a smaller percentage of the uprated feedwater flow. This decreases the relative amount of subcooling from the HPCI flow and margin is increased for this event. Also, the HPCI system at Hope Creek is designed to deliver a substantial portion (greater than 30%) of flow to the core spray sparger. As the core spray sparger path does not contribute to the core inlet subcooling, this design reduces the severity of an inadvertent HPCI actuation.

The Turbine Trip, bypass failure, with scram on high flux (item 13 in Table E-1, ELTR1) was considered as a potential limiting overpressure event for the ELTR1. However, this event has been determined to be generically non-limiting compared to the MSIV closure due to the differences in the dynamic response and the increased steam volume associated with a turbine trip stop valve closure. Therefore, this event was not re-analyzed.

3.22 In the Hope Creek PUSAR, In the second paragraph on page 9-2, the 25% of rated thermal power value for Technical Specification (TS) safety limit, limiting condition for operation thresholds and Surveillance Requirement thresholds is modified to 24% based on the uprated bundle power. The 25% is based on generic analysis with highest average bundle power for BWR6, which is 4.8 Mwt/bundle. The staff is concerned that this modified value (24%) will be less conservative for Hope Creek (BWR4) core since this value is obtained from the ratio of "highest" bundle power value of BWR6 (4.8 MWT/bundle) and "average" BWR4 uprated bundle power. Shouldn't the divisor be the "highest" uprated bundle power instead of "average" uprated bundle power? Please address this concern. Please also list the affected safety limits and thresholds for the staff to evaluate.

Response

As stated in PUSAR Section 9.1.1, the 25% of Rated Thermal Power (RTP) Safety Limit is based on a conservative generic analysis utilizing core conditions for a BWR that has the highest average bundle power (at 100% RTP) for all BWR product lines. The average bundle power is defined as the 100% RTP divided by the total number of assemblies in the core. Based on this, the highest average bundle power for all BWR product lines (as originally licensed) is 4.8 MWt/bundle, and occurs in the BWR6 product line. The average bundle power for all other BWR product lines (as originally licensed) is less than 4.8 MWt/bundle. However, since the average bundle power for HCGS at CPPU is 5.03 MWt as documented in PUSAR Section 9.1.1, the original generic basis is not longer bounding and the Safety Limit must be adjusted. The value for the Safety Limit for CPPU is determined for Hope Creek by scaling the generic 25% value by the ratio of 4.8/5.03. The scaling ratio is the ratio of average bundle powers from the generic analysis to the average bundle power at CPPU conditions. The 4.8 MWt is an average bundle power at the original rated power,

which is the maximum for the BWR fleet. This ensures that the safety limit is no higher than any other previously approved BWR.

The generic 25% RTP Safety Limit is conservatively applied to other reactor types, such as HCGS, which is a BWR4 type reactor. The TS basis for this safety limit is generic and independent of BWR product line. The TS safety limit is based on critical power testing at the lowest achievable flow rate. The TS bases document a high level of conservatism as it would take a core power level > 50% with design peaking factors to have a bundle in transition boiling compared to the ~25% power safety limit. The design peaking factor includes the effect of radial bundle power peaking. The scaling approach used for HCGS ensures the safety limit power level is less than or equal to any other previously approved BWR.

The affected Safety Limits and thresholds are identified and discussed in Table 1 in Attachment 1 to the HCGS EPU submittal.

3.23 Based on Table 9-2 In the Hope Creek PUSAR, what will be the final value of OLMCPR in this EPU core, Option A values or B? Please explain why option A and B for OLMCPR are the same for Loss of Feedwater Heating and Rod Withdrawal Error accidents. Please explain why Option A OLMCPRs in Table 9-2 anticipated operational occurrences are not simply SLMCPR (1.10) plus ΔCPR. What is the ΔCPR for main steam isolation valve (MSIV) closure with flux scram?

Response

The Option A and Option B OLMCPR values in Table 9-2 are associated with the assumed control rod scram speed. The Option A values are based on the specified minimum allowable Technical Specification scram speed. The Option B values are based on an assumed scram speed more representative of actual Control Rod Drive (CRD) performance. Typically, the Option B OLMCPR value is used for operation and the Option B limit is what would be used. Periodic CRD scram time surveillances are performed during the operating cycle to confirm the continued applicability of the Option B value. The Option A value is available if the Option B value cannot be confirmed.

The Option A and Option B OLMCPR values pertain to transient events in which a reactor scram is initiated as a mitigating action, such as a Turbine Trip With Bypass Failure. The Loss of Feedwater Heating and Rod Withdrawal Error events do not typically result in a power increase that would reach the scram setpoint, and the analyses conservatively assume a scram does not occur. Therefore, only a single value of OLMCPR is determined, which is independent of scram speed.

The values of ΔCPR presented in Table 9-2 are based on the Option B scram speed. The Option B OLMCPR values are based on the SLMCPR plus the

ΔCPR and additional CPR adders required to address analysis uncertainties such as the model uncertainty and the power uncertainty. The Option A OLMCPR values are based on the Option B values plus an additional conservative CPR adder to address the impact of the slower Technical Specification scram speed.

The MSIV Closure with Flux Scram event is the basis for demonstrating ASME reactor overpressure compliance as described in PUSAR Section 3.1. This event is not considered an Anticipated Operational Occurrence (AOO) (it is classified as an infrequent event). The acceptance criteria for infrequent events, including the MSIV Closure with Flux Scram event, do not include the fuel thermal limit criteria, such as CPR, that are evaluated for AOOs. Therefore, ΔCPR is not evaluated for the MSIV Closure with Flux Scram event.

3.24 Please provide CPPU loss of feedwater flow and loss of one feedwater pump transient key parameter plots like Figures 9-1 to 9-4. For loss of feedwater transient, Hope Creek EPU mixed core (non GE-14 equilibrium) has different decay heat value than the one (GE-14 equilibrium) used in the analysis. How much does it affect the level recovery time? In terms of uncertainties, how does decay heat model used in your loss of feedwater flow analysis compare with the decay heat (decay heat >= 1979 ANS + 10%) suggested in ELTR1? Please also provide an estimate of lowest inside core shroud level in this transient. How does the calculated lowest level compare to Level 1? In loss of one feedwater pump transient, was Level 3 scram avoided?

Response

The Loss of Feedwater Flow and the Loss of One Feedwater Pump transient key parameters are shown in Figures 3.24-1 and 3.24-2 respectively. The Level 3 scram was avoided in the Loss of One Feedwater Pump simulation.

In general, decay heat is not a strong function of fuel product line or fuel manufacturer. A comparison study had been performed to compare the ANS 5.1-1979 Standard decay heat result of a SVEA 96+ bundle with that of a GE14 bundle of comparable enrichment. The resulting differences were well within the calculation uncertainties, and hence provided justification that the HCGS EPU decay heat bases remain valid for a mixed core of SVEA 96+/GE14. Furthermore, the Loss of Feedwater safety analysis for determining the margin to the top of active fuel uses the ANS 5.1 1979 decay heat + 10%, bounding all fuel types used at HCGS. The lowest level inside the core shroud was calculated to be 446" above vessel zero, which is more than 6 feet above the top of active fuel. A separate nominal Loss of Feedwater analysis was performed to compare the level in the downcomer to the operational limit for Level 1 as it is desirable to avoid Level 1 during a complete loss of feedwater. The downcomer level in this analysis was 417" above vessel zero, which was about 11" above the Level 1 operational limit.

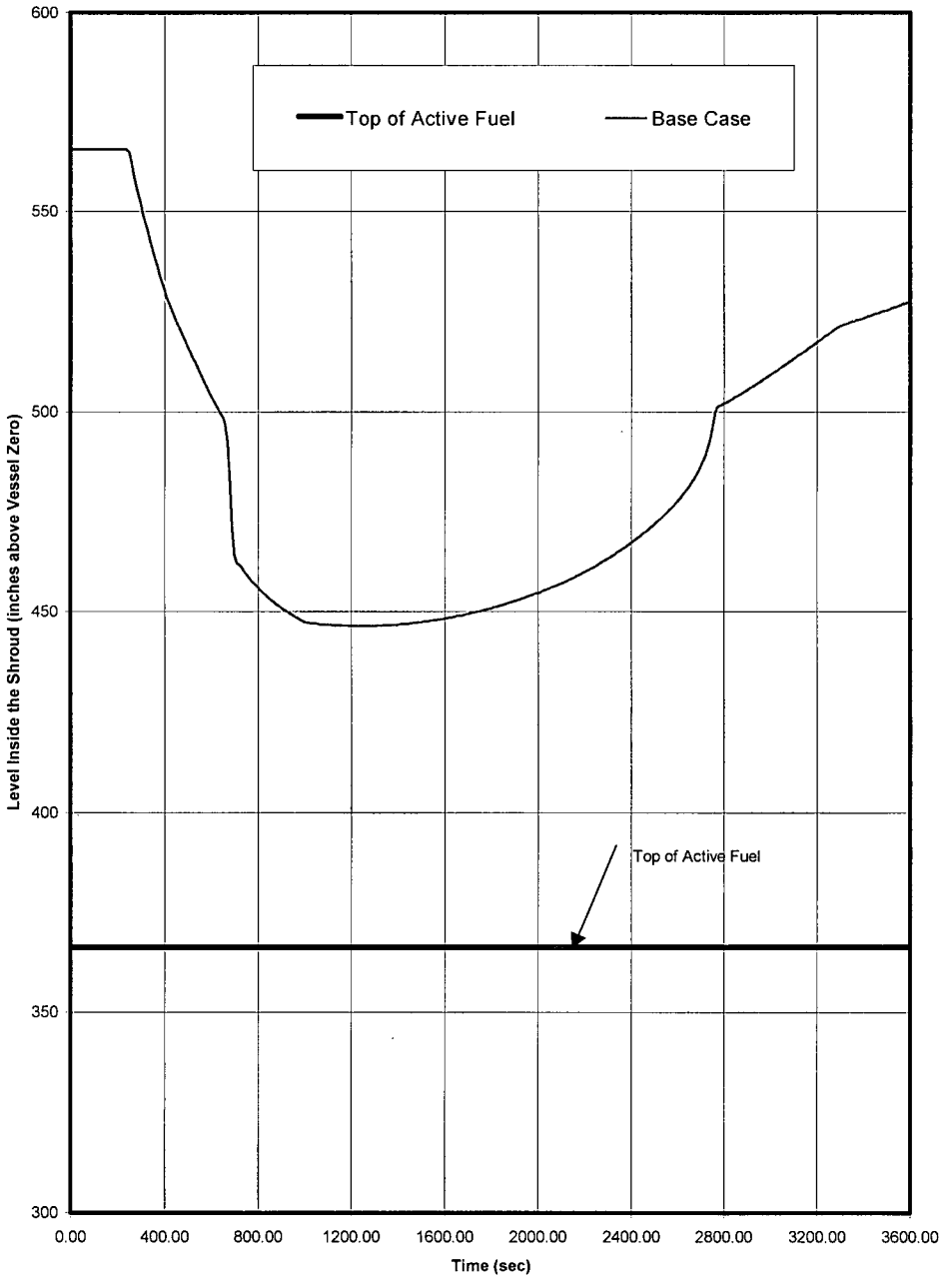

Figure 3.24-1 Loss of Feedwater Long Term Level Response

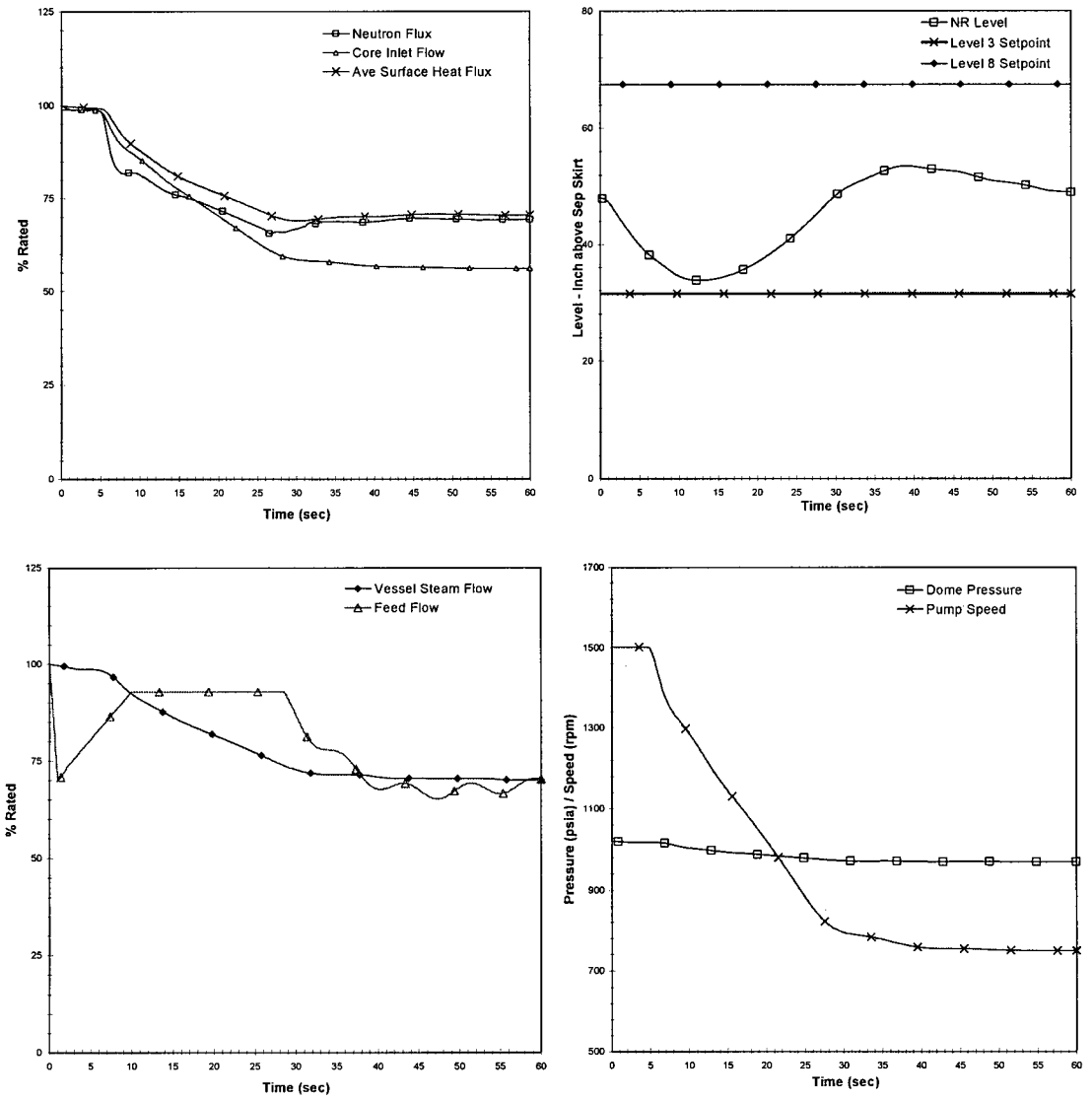

Figure 3.24-2 Loss of One Feedwater Pump Transient Response

3.25 Question Deleted.

3.26 Is GE 14 equilibrium core used in all section 9.2 design basis accidents analysis? Please clarify this assumption used in 9.1.1. Please clarify what is meant by "CPPU core inventory" cited throughout section 9.2.

Response
The analyses presented in the PUSAR, including Section 9, are based on an equilibrium core composed of all GE14 fuel. The analyses presented in PUSAR Section 9.1, are based on an equilibrium GE14 core at the CPPU power level of 3840 MWt, with either a direct or statistical treatment for 2% power uncertainty. The analyses presented in PUSAR Section 9.2, are based on an equilibrium GE14 core at a conservative power level of 4031 MWt (3952 MWt x 1.02). The use of the phrase "CPPU core inventory" in PUSAR Section 9.2 refers to the end of cycle bundle discharge fission product inventory of the equilibrium core design, which is bounding for GE14 and earlier GE fuel designs. The "CPPU core inventory" is the source term basis for the radiological dose consequence assessments presented in PUSAR Section 9.2.

3.27 In Table 9-9, with higher power density in constant pressure power uprate operation, why is the PCT (1446) is lower than the value in CLTP (1589)?

Response
To calculate the PCT values during the ATWS conditions, a conservative initial critical power ratio (CPR) is assumed in the evaluation. The same conservative initial CPR value is assumed for both the EPU and CLTP cases. Since the overall EPU core power is higher than the CLTP core power, the initial radial peaking power for the hot channel in the EPU case must be lower than that of the CLTP case to achieve the same initial CPR value. This results in the EPU hot channel(s) having a less limiting initial power to flow ratio. The fuel rods in the hot channel(s) for the EPU case can experience a less severe dryout than those in the CLTP case and thus a lower PCT value. Another factor that can impact the PCT values is the axial power shape. The impact of the axial power shape to PCT is demonstrated in the difference between beginning of cycle (BOC) and end of cycle (EOC) conditions. The BOC condition has a bottom-peak axial power shape and EOC condition has a top-peak one. The resulting PCT for the EOC conditions is higher than that for the BOC conditions. The axial power shape for the CLTP case at the EOC conditions is more top-peaked and thus, contributes to the higher PCT value.

3.28 Please document the sequence of events for the analyzed ATWS transients and identify the most limiting event in section 9.3.1.

Response
The ATWS events evaluated for EPU are defined in ELTR 1. These events have

been demonstrated to be the limiting events for ATWS and include the Main Steam Isolation Valve Closure (MSIVC), the Pressure Regulator Failure Open (PRFO), the Loss of Offsite Power (LOOP) and the Inadvertent Opening of a Relief Valve (IORV). These events were evaluated at both beginning of cycle (BOC) and end of cycle (EOC) conditions to determine the most limiting condition. For HCGS, the limiting event was determined to be the PRFO event. The key results for this event are reported in PUSAR Table 9-9.

The sequence of events for the analyzed ATWS events (for EOC conditions) are provided in the Tables 3.28-1 thru 3.28-4.

Table 3.28-1 MSIVC Event Sequence at EOC

Item	Response	Event Time (sec)
1	MSIV Isolation Initiates	0.0
2	High Pressure ATWS Setpoint	3.9
3	MSIVs Fully Closed	4.0
4	Peak Neutron Flux	4.0
5	Opening of the First Relief Valve Tripped	4.1
6	Recirculation Pumps Tripped	4.4
7	Peak Heat Flux Occurs	4.9
8	Peak Vessel Pressure	8.7
9	Feedwater Reduction Initiated	30
10	SLCS Pumps Start	234
11	Boron Solution Reaches Upper Plenum*	320
12	Hot Shutdown Achieved (Neutron flux below 0.1% for more than 100 seconds)	682
13	Peak Suppression Pool Temperature**	5616

* Based on a boron transportation delay time of 86 seconds.
** Based on STEMP model without vessel depressurization.

Table 3.28-2 PRFO Event Sequence at EOC

Item	Response	Event Time (sec)
1	Turbine Control and Bypass Valves Start Open	0.1
2	MSIV Closure Initiated by Low Steamline Pressure	15.7
3	MSIVs Fully Closed	19.7
4	Peak Neutron Flux	20.5
5	High Pressure ATWS Setpoint Tripped	22.5
6	Opening of the First Relief Valve Tripped	22.6
7	Recirculation Pumps Tripped	23.0
8	Peak Heat Flux Occurs	23.4
9	Peak Vessel Pressure	27.7
10	Feedwater Pumps Runback Initiated	48.2
11	SLCS Pumps Start	252
12	Boron Solution Reaches Upper Plenum*	356
13	Hot Shutdown Achieved (Neutron flux below 0.1% for more than 100 seconds)	725
14	Peak Suppression Pool Temperature**	5285

* Based on a boron transportation delay time of 104.4 seconds.
** Based on STEMP model without vessel depressurization.

Table 3.28-3 LOOP Event Sequence at EOC

Item	Response	Event Time (sec)
1	Main Turbine Generator Tripped	0.0
2	Recirculation Pumps Tripped	0.0
3	Feedwater Pumps coastdown initiated	0.0
4	Peak Neutron Flux	0.7
5	High Pressure ATWS Setpoint Reached	0.9
6	Peak Heat Flux	1.1
7	Opening of the First Relief Valve Tripped	1.1
8	MSIV Isolation Initiated	2.0
9	Peak Vessel Pressure	4.5
10	MSIVs Fully Closed	6.0
11	SLCS Pumps Start	231
12	Boron Solution Reaches Upper Plenum*	317
13	Hot Shutdown Achieved (Neutron flux below 0.1% for more than 100 seconds)	695
14	Peak Suppression Pool Temperature**	6510

* Based on a boron transportation delay time of 86 seconds.
** Based on STEMP model without vessel depressurization.

Table 3.28-4 IORV Event Sequence at EOC

Item	Response	Event Time (sec)
1	Inadvertent Opening of One Relief Valve	0.0
2	Peak Neutron Flux	0.0
3	Peak Vessel Pressure	0.0
4	Peak Heat Flux Occurs	0.2
5	Boron Injection Initiation Temperature (BIIT) Reached	422
6	Recirculation Pumps Tripped	422
7	Feedwater Reduction Initiated	422
8	SLCS Pumps Start	422
9	Boron Solution Reaches Upper Plenum*	508
10	Hot Shutdown Achieved (Neutron flux below 0.1% for more than 100 seconds)	864
11	Peak Suppression Pool Temperature**	15000

* Based on a boron transportation delay time of 86 seconds.
** Based on STEMP model without vessel depressurization.

3.30 Please explain in more details why "the core design necessary to achieve CPPU operation may affect the susceptibility to coupled thermal-hydraulic/neutronic core oscillation at natural circulation condition" described in first paragraph of section 9.3.3?

Response
To achieve CPPU operation, the core design will tend to require a higher enriched fuel, which might result in a larger void coefficient (absolute). A more negative core void coefficient produces a greater power change for a change in void content, which is a less stable condition and also tends to exacerbate power oscillations.

The fuel design to achieve CPPU may be switched from a 9x9 fuel design to a 10x10 fuel design, which results a smaller fuel thermal time constant. Reducing fuel thermal time constant makes the core less stable. However, for the HCGS EPU application, this is not the case as both SVEA 96+ and GE14 are 10x10 fuel designs.

In addition, because of the fuel design change, the two-phase to single-phase pressure drop ratio may be increased. Increasing the two-phase to single-phase pressure drop ratio tends to make the core less stable.

These three parameters will affect the susceptibility to coupled thermal-hydraulic/neutronic core oscillations at natural circulation conditions. It is noted that one mitigating factor for the CPPU core design is that the radial peaking profile tends to be flatter relative to the pre-CPPU core design and this will improve plant stability, reducing the susceptibility to oscillations. The response to RAI 3.46 provides a comparison of calculated decay ratios for pre-CPPU and CPPU conditions. The results indicate the relatively small changes in overall reactor stability based on the factors discussed above.

3.31 Question Deleted.

3.32 In feedwater heater out of service and final feedwater temperature reduction transients, feedwater temperature is lower and thus the power is supposed to be higher during the transient. Even with less moderator reactivity being inserted (due to smaller difference between initial and final feedwater temperatures), isn't the higher power at same low flow rate supposed to have higher ATWS oscillation?

Response
Feedwater heater out of service (FWHOOS) and final feedwater temperature reduction (FFWTR) are operational flexibility options that allow continued operation with reduced feedwater temperature. Initial power is unchanged for

both the FWHOOS and FFWTR conditions – the additional reactivity associated with the reduced feedwater temperature is typically offset with control rods, as needed. For both the FWHOOS and FFWTR conditions, an ATWS event analysis would be initiated from the same limiting power/flow statepoint assumed for the normal feedwater temperature case (statepoint 'D' in PUSAR Fig. 1-1) and transition to essentially the same natural circulation statepoint (statepoint 'J' in PUSAR Fig. 1-1) prior to the onset of power oscillations. Therefore, as described in PUSAR Section 9.3.3, power oscillations for the FWHOOS and FFWTR operating conditions are expected to be no worse than for the analyzed normal feedwater temperature condition.

3.33 Figure 9-1 (Turbine Trip with Bypass Failure), it showed steam flow (70%) out of vessel (peak around 1.2 sec) before t = 2 sec when no relief flows were shown according to the upper right plot. The staff is concerned that the large steam flow after reactor dome being pressurized is unrealistic because steam line is pressurized soon after stop valve closes and pressure difference between reactor dome and steam line should be smaller than the model's estimate. Please justify this calculation and provide real plant turbine trip steam flow and dome pressure data for Hope Creek or a similar plant.

Response

The steam flow response illustrated in PUSAR Figure 9-1 is typical of rapid pressurization transients such as a Turbine Trip with Bypass Failure or a Generator Load Rejection with Bypass Failure (PUSAR Figure 9-2). These events are characterized by a rapid shutoff of the steam flow to the turbine by the Turbine Stop Valves (TSV) or Turbine Control Valves (TCV) near the end of the steam lines. The shutoff of the steam flow results in a significant, and rapid pressurization at the turbine valves and a strong dynamic response in the steam lines. The local pressurization at the turbine valves creates a 'compression wave' that travels at sonic velocity (~1600 ft/sec) through the steam lines towards the reactor vessel. When the compression wave reaches the reactor vessel (at the steam line nozzles), the resulting pressure and momentum effects are sufficient to reverse the steam flow slightly, back into the reactor vessel. The reactor vessel acts as a fixed boundary and reflects the compression wave back toward the turbine valves resulting in the rapid increase in vessel steam flow observed between approximately 1.0 seconds and 1.2 seconds. Subsequently, the compression wave reflects back from the closed turbine valves towards the reactor vessel again and generates another steam flow oscillation (decrease followed by an increase) between approximately 1.2 seconds and 2.0 seconds, similar to the first. The opening of the Safety Relief Valves at approximately 2.0 seconds effectively dampens, but does not eliminate, the compression wave. The oscillatory behavior of the steam flow remains, but at a much reduced magnitude.

Steam line modeling in ODYN is described in Reference 3.33-1. RAI 19 in Reference 3.33-1 describes steam line noding and other sensitivity studies and illustrates some steam line pressure dynamics. This reference also shows comparisons to plant turbine trip data where the reactor pressure is conservatively predicted.

Reference

3.33-1 NEDO-24154-A, Qualification of the One-Dimensional Core Transient Model for BWRs, Volume 1-3, August, 1986.

3.34 In Figure 9-4, the core inlet flow plot does not seem to show reactor pump trip out of service. Please explain the difference between this transient and the one in Figure 9-3.

Response

The analysis results presented in PUSAR Figure 9-4 are based on the assumption that the recirculation pump trip function is out of service. This recirculation pump trip function is the End-of-Cycle Recirculation Pump Trip (EOC-RPT) function identified in PUSAR Table 1-3. The EOC-RPT function is designed to provide a rapid trip of the recirculation pump motor based on a signal from the Reactor Protection System (RPS). The recirculation pump motor trip results in a rapid reduction in core flow and thus will reduce the severity (i.e., power increase) of rapid pressurization type transients.

In addition to the EOC-RPT feature, the HCGS design includes another recirculation pump trip function, known as the ATWS-RPT as discussed in PUSAR section 9.3.1. This function is designed to mitigate the impact of postulated ATWS events and is initiated by reactor vessel high pressure or reactor low level. The ATWS-RPT function is not designed to reduce the severity (i.e., power increase) of rapid pressurization type transients. The ATWS-RPT high pressure trip signal occurs later in pressurization events than the EOC-RPT trip signal initiated by RPS. The reduction of core flow illustrated in PUSAR Figure 9-4 is the result of the ATWS-RPT function. The EOC-RPT function was assumed to be out of service in this analysis.

The analysis results presented in PUSAR Figure 9-3 include the initiation of the EOC-RPT function. Because of the rapid initiation of the EOC-RPT function by the RPS, the reactor core flow is reduced earlier in the event, during the critical period when reactor power is increasing. This reduction in core flow reduces the peak reactor power (neutron flux in PUSAR Figure 9-3) and reduces the ΔCPR response as compared to the case with the EOC-RPT out of service (PUSAR Figure 9-4). However, the case with the EOC-RPT function out of service activates the ATWS-RPT high pressure trip about 1 sec after the turbine trip and this is why figures 9-3 and 9-4 look very similar.

3.35 Please provide the maximum vessel dome pressure for the transients shown in Figure 9-1 to 9-4. The plots show pressure rise in % rated. What is the rated pressure rise for Hope Creek?

Response
The scale on PUSAR Figures 9-1 to 9-4 for pressure is in units of psig as annotated in the legend. The calculated maximum vessel pressure (at the bottom of the vessel) for the transient events illustrated in Figures 9-1 to 9-4 is as follows:

1. Fig. 9-1 (TTNBP) – 1232.4 psig
2. Fig. 9-2 (LRNBP) – 1231.7 psig
3. Fig. 9-3 (FWCF) – 1204.2 psig
4. Fig. 9-4 (FWCF No RPT) – 1206.7 psig

There is no "rated pressure rise" for transient events – the transient reactor pressure is calculated for each event. However, a maximum pressure acceptance criterion is established for transient events. This acceptance criterion is based on the ASME code allowable peak pressure of 1375 psig (110% of design value). The results of the transient events illustrated in Figures 9-1 to 9-4 meet the pressure acceptance criterion.

Stability

Bypass Voiding

3.36 Characterize the expected amount of bypass voiding under CPPU conditions. Provide the expected bypass void level at points J, D, and E of Figure 1.1 of NEDC-33076P, Rev. 2, using a methodology equivalent to that used by [ISCOR] for both hot and average channel.

Response
ISCOR is a thermal hydraulic analysis code used by GNF as part of the GESTAR II licensing process. Previous RAIs (MFN 06-211) have established that the "hot channel" bypass void fraction calculated by ISCOR is significantly conservative with respect to best estimate models. The final core design, and thus the bypass voiding analysis for Hope Creek Cycle 15, has not yet been completed. The bypass voiding has been previously analyzed for Cycle 14 which had originally been intended as the first EPU cycle. The analysis for Cycle 14 EPU using ISCOR showed the hot channel bypass voiding at point E to be [[ ]] while the average channel bypass voiding was shown to be [[ ]]. As the final core design for Cycle 15 is developed and licensing analysis completed, the results for bypass voiding at points J, D, and E will be evaluated and provided when available.

Effect of bypass voids on instrumentation during normal operation

3.37 Reliability of the local power range monitor (LPRM) instrumentation and accurate prediction of in-bundle pin powers typically requires operation with bypass voids lower than 5% at nominal conditions (e.g., point E of Fig 1.1 of NEDC-33076P, Rev. 2). If the expected bypass void conditions at CPPU are greater than 5%, evaluate the impact on (1) reliability of LPRM instrumentation, (2) accuracy of LPRM instrumentation, and (3) in-bundle pin powers.

Response

The impact of voiding in the bypass region on the thermal neutron flux sensitive local power range neutron detectors (LPRMs) is to reduce the measured response for the same power generated in the adjacent fuel. There is no effect on the gamma flux. The reduction in thermal neutron flux is due to a decrease in the moderation, which decreases the thermal neutron flux incident on the detectors for the same neutron flux generated in the adjacent fuel. The impact is greatest for the highest elevation LPRM (D level) when the reactor is operating at a state point at which the highest bypass voiding occurs.

The effect of bypass voids on the thermal flux at the LPRM detector was calculated using an accurate 3 dimensional Monte Carlo neutron transport code (MCNP) with neutron cross-sections that vary continuously with energy. The results showed that for X % bypass voids the thermal neutron flux at the LPRM detector is reduced by 0.5X % (Reference 3.37-1). The reduction in neutron flux can potentially impact the local power measurement and the MCPR determination. However the impact is small. Studies were performed for 5% bypass voids in the hot channel at the LPRM D elevation. These studies evaluated the potential impact on TIP and LPRM Local Power Measurement, impact on MCPR and impact on APRM Average Power Measurements. Results show that for the 5% bypass void condition, the impact on these parameters is negligible.

For HCGS EPU MELLLA operation, the calculated maximum D level bypass voids for a hot channel is 2.3% at rated power and flow (Point E of Fig 1.1 of NEDC-33076P, Rev 2), and 2.8% at rated power and 94.6% flow. These values are approximately equivalent to the 2.9% hot channel D level bypass voids for 87% power (i.e., the 100% CLTP power level) and 76.6% flow on the EPU MELLLA line, and less than 5% limit. Therefore for normal steady state EPU MELLLA operation, no significant bypass voids impact is expected on (1) reliability of LPRM instrumentation, (2) accuracy of LPRM instrumentation, and (3) in-bundle pin powers.

Reference

3.37-1 Interim Methods Licensing Topical Report "Applicability of GE Methods to Expanded Operating Domains", NEDC-33173P, Feb 2006

Effect of bypass voids on instrumentation to detect and suppress (D&S) unstable oscillations

3.38 The presence of bypass voids affects the LPRM calibration. Evaluate the expected calibration error on operating power range monitor (OPRM) and average power range monitor (APRM) cells induced by the expected level of bypass voids. Document the impact of this error on the D&S Option III scram setpoint.

Response
The impact of bypass voids on the LPRM, APRM performance in the MELLLA region for steady state operation has been described in response to RAI 3.37. This response deals specifically with the impact during transient conditions, including two pump trip when the power and flow decrease along the MELLLA power-flow line down to natural circulation levels where the bypass voids are highest. Impact on MCPR is not considered, since MCPR is only calculated for steady state operation.

Impact on APRM and LPRM Transient Performance
As discussed in response to RAI 3.37, the presence of bypass voids leads to a percentage reduction in neutron flux (and consequently the measured LPRM signal). The hot channel D level LPRM is the detector in the region with maximum bypass voids, so it is affected the most. The APRM reads the average of the LPRMs in the core and since the bypass voids are significantly less at most other LPRM locations, the APRM signal is not affected significantly. For evaluating the impact of bypass voids on transients for MELLLA operation, only those transients that are mitigated by instruments based on LPRM signals need to be considered. For Hope Creek, there are two types of transients that need to be considered for this evaluation[1]:

1. Overpower transients from steady state operating conditions that are mitigated by APRM scram and rod block.

2. Stability transients at low flow conditions that are mitigated by the OPRM instrument which uses LPRM inputs.

Overpower Transients
For overpower transients mitigated by APRM scram and rod block, the greatest impact of bypass voids is mitigating overpower transients from low flow steady state operating conditions where the bypass voids are the greatest. However ISCOR runs for Hope Creek show that although there are voids at the D level for

[1] Note that RBM rod block setpoints which mitigate rod withdrawal error transients are based on relative flux, and are not impacted by bypass voids.

the hot channel at low flows, there are virtually no bypass voids on a core average basis. Thus, since the APRM measures core average power, the impact of bypass voids on APRM setpoints that mitigate overpower transients, is negligible for MELLLA operation.

Stability Transients

For stability transients, mitigated by OPRM instruments that use LPRM inputs, the worst case bypass voiding condition exists at natural circulation after trip of both recirculation pumps from normal operation in the MELLLA region. ISCOR calculations for Hope Creek show that at this condition (flow ~33.6% and power ~51.4%) and for a typical radial peaking factor of 1.28, the hot channel bypass voids at the D, C, B and A levels are approximately 18%, 6.2%, 0% and 0% respectively. The result of these bypass voids is to depress the hot channel flux at the D, C, B and A levels by approximately 9%, 3.1%, 0% and 0% respectively (Reference 3.38-1).

The OPRM measures the power oscillation magnitude in various "cells" based on averaging the readings from typically 4 LPRMs assigned to that cell, and triggers mitigation actions if the oscillation amplitude is larger than a pre-determined setpoint. The presence of bypass voids around an LPRM potentially reduces the indicated LPRM reading, and this reduces the measured oscillation magnitude causing a non-conservative impact on the setpoint.

A conservative estimate of the impact of bypass voids on the OPRM setpoint can be obtained by considering only the reduction in oscillation amplitude due to bypass voids (Reference 3.38-1), and noting that the Hope Creek OPRM cell design contains 4 LPRMs with one detector from each of the D, C, B, A levels. Thus, for the hot channel OPRM cell the flux at the LPRMs is reduced by 9%, 3.1%, 0% and 0% at the D, C, B and A elevations. This represents a conservative condition because it assumes that the D, C, B, A levels from LPRMs that input to the OPRM are all surrounded by four high power bundles with a 1.28 peaking factor. For this condition, the average reduction in hot channel OPRM cell response due to bypass voids is approximately 3%, assuming all LPRMs see the same flux. This is also conservative because generally the D level LPRM which has the most bypass voids, also has the lowest flux. Based on the bypass void impact of 3% amplitude reduction, a 15% power oscillation would appear as a measured OPRM oscillation of approximately 14.55%. So to trip on a 15% power oscillation, the setpoint would need to be reduced from 1.15 to 1.1455 to account for bypass voids. This small amount of reduction, which has been determined conservatively, does not have a significant impact as stated in Reference 3.38-1.

Reference

3.38-1 Interim Methods Licensing Topical Report "Applicability of GE Methods to Expanded Operating Domains", NEDC-33173P, Feb 2006

D&S Setpoint calculations

3.39 NEDO-33190 and NEDO 33188 show an example setpoint calculation for Cycles 13 and 14 respectively. These setpoints do not appear to include an uncertainty term reflecting the possible LPRM miss-calibration under bypass void conditions. How is this uncertainty accounted for?

Response
The impact of bypass voids was not considered for Hope Creek cycles 13 and 14, and no setpoint penalty was imposed, because the effect had not been identified at the time these analyses were performed. Since then the impact of bypass voids has been evaluated and quantified as described in response to RAI 3.38, and for the Hope Creek Option III OPRM configuration, a conservative setpoint penalty of 3% is calculated for typical peaking factors (Reference 3.39-1). As a result, a small OPRM setpoint penalty is expected to be applied for EPU applications that utilize Reference 3.39-1. A preliminary draft SER for Reference 3.39-1 indicates that a 5% setpoint penalty may need to be considered for Option III setpoints due to bypass voids. The HCGS OPRM setpoints for EPU conditions will be calculated in accordance with this restriction, as applicable.

Reference
3.39-1 Interim Methods Licensing Topical Report "Applicability of GE Methods to Expanded Operating Domains", NEDC-33173P, Feb 2006

DIVOM applicability to future cycles

3.40 NEDC-33185P states that the Cycle 13 DIVOM correlation may be used for future cycles based on an evaluation. Revision 1 NEDC-3318[6]P shows a significantly larger (non-conservative) DIVOM slope for Cycle 14 under CPPU conditions, and it does not state that the Cycle 14 DIVOM slope may be used for future cycles. Please document which DIVOM slope will be used for future CPPU cycles and which methodology will be used to (1) calculate it, or (2) evaluate the adequacy of an older slope.

Response
The DIVOM analysis documented in NEDC-33186P, Revision 1 "MELLLA TRACG DIVOM Evaluation for Hope Creek at CPPU Conditions" is based on an assumed, representative CPPU core design for Cycle 14. The purpose of the report was to estimate the potential impact of both MELLLA and CPPU operation on the calculated DIVOM slope. The MELLLA operating domain results in operation on higher control rod lines as compared to the Cycle 13 operating domain (ELLLA) evaluated in NEDC-33185P, "Hope Creek Cycle 13 TRACG DIVOM Study (ELLLA)." Therefore, the DIVOM analysis statepoint on the natural circulation line following a postulated two pump trip is at a higher absolute power

level. The higher calculated DIVOM slope in NEDC-33186P, Revision 1 is consistent with this higher power level.

The analysis in NEDC-33186P, Revision 1 is not based on an actual operating core design, and is not intended for actual application to HCGS. Therefore, the results are not considered applicable to HCGS operation and a statement of applicability to future cycles was not included in the report.

All future operating cycles will include a cycle specific evaluation or calculation of the DIVOM slope based on the NRC approved methodology and performed in accordance with the BWROG Plant-Specific Regional Mode DIVOM Procedure Guideline (GE-NE-0000-0028-9714-R1, June 2005).

DIVOM slope for Cycle 14 under CPPU conditions

3.41 The recommended DIVOM slope in NEDC-3318[6]P Revision 1 for Cycle 14 under CPPU conditions uses a radial peaking uncertainty that is half of that assumed for Cycle 13 in NEDC-33185P under OLTP conditions. Justify the use of this smaller uncertainty.

Response
The Option III licensing analysis methodology consists of three major components:

1. A determination of the MCPR margin that exists prior to the onset of the oscillation

   The plant and cycle specific MCPR is evaluated to determine the margin to the SLMCPR prior to the oscillation.

2. A statistical treatment of parameters that influence the magnitude of the peak fuel bundle power oscillation, including power distributions, oscillation contours, oscillation growth rates, frequencies, trip overshoot, and LPRM failures

   The result of the statistical evaluation is a conservative value of the peak bundle power oscillation magnitude for anticipated reactor instability events. For a given combination of LPRM assignments to OPRM cells and trip setpoint, this statistical analysis calculates the hot channel oscillation magnitude (HCOM) prior to termination of the instability.

3. A conservative relationship between the change in CPR and the hot channel oscillation magnitude (known as the DIVOM)

This relationship is derived from fuel vendor analyses (GE uses the 3-D TRACG model) performed over a range of conditions selected to represent the current fuel design for a given plant. As a result of MFN-01-046, GENE 10 CFR Part 21 Notification, Stability Reload Licensing Calculations Using Generic DIVOM Curve, August 31, 2001," plant-specific DIVOM curves are now utilized in lieu of the generic DIVOM curve in NEDO-32465-A.

The procedure guideline developed by the BWROG for performing plant specific DIVOM calculations (GE-NE-0000-0028-9714-R1, "Plant-Specific Regional Mode DIVOM Procedure Guideline") recommends that potential variation in radial peaking should be considered when performing DIVOM calculations. The guideline states "There should be some consideration in the procedure for changes in radial peaking from the design calculations. The goal is to reasonably represent expected variations in radial peaking factor as the result of normal operation." The procedure guideline does not specify any specific value for the assumed variation.

The TRACG stability analysis is performed first using a nominal control rod pattern. If this does not result in growing oscillations, then a more conservative Savoia rod pattern is used (i.e., a rod pattern that results in a more peaked, less stable condition), which typically produces growing oscillations. Next, the analysis is repeated with a radial peaking factor multiplier. Typically, this multiplier places the limiting CPR channel at or near the OLMPCR. This analysis approach produces a reasonable value for the slope of the DIVOM curve, consistent with the Option III licensing basis.

For the first application of a plant specific DIVOM in NEDC-33185P, HCGS chose to utilize a conservative bounding value for radial peaking variation. A conservative, but more expected value was selected in the NEDC-33186P Revision 1 CPPU analysis. As stated previously, the analysis in NEDC-33186P Revision 1 is not based on an actual operating core design, and is not intended for actual application to HCGS.

<u>Interface between GE Methods and existing Solution III hardware</u>

3.42 Provide a short summary of the Solution III hardware currently installed in Hope Creek. Are there any issues related to the interface between the existing hardware and GE methods?

<u>Response</u>
The HCGS Option III OPRM system is manufactured by ABB and is designed to initiate a reactor scram via existing reactor protection system (RPS) trip logic upon detection of conditions consistent with the onset of local oscillations in core power and the approach to conditions required for sustained oscillations and a

thermal-hydraulic instability event. This capability will assure protection of the MCPR safety limit under anticipated core-wide and regional T-H instability events.

The design and effectiveness of the OPRM system in meeting the regulatory requirement to detect and suppress conditions necessary to initiate T-H instability is documented in the following NRC accepted topical reports:

NEDO-32465-A, August 1996	BWROG Reactor Core Stability Detect and Suppress Solutions Licensing Basis Methodology and Reload Applications
NEDO-31960-A, November 1995	BWROG Long-Term Stability Solutions Licensing Methodology
NEDO-31960-A, Supplement 1, November 1995	BWROG Long-Term Stability Solutions Licensing Methodology
CENPD-400-P-A, Rev. 1, May 1995	Generic Topical Report for the ABB Option III Oscillation Power Range Monitor (OPRM)

The HCGS OPRM system is comprised of four OPRM channels that provide inputs to an associated RPS channel via eight OPRM modules. The OPRM modules are installed in available locations in the associated LPRM pages in the power range neutron monitoring system (PRNMS) panels. Each OPRM channel takes amplified LPRM signals from one APRM group and either another APRM group or one unassigned LPRM group. The LPRM signals are grouped together such that the resulting OPRM response provides adequate coverage of anticipated oscillation modes. Each OPRM channel consists of two OPRM modules and contains more than 30 OPRM cells, where a cell represents a combination of four LPRMs in adjacent areas of the core. The use of instantaneous flux and smaller grouping of LPRMs in cells provides better resolution for the detection of local oscillations than the APRM system alone. With many cells, each consisting of multiple LPRMs in close proximity, the sensitivity of the OPRM is not adversely impacted by single LPRM failures.

The licensing basis of the Option III methodology is the same for both the GE and ABB OPRM designs. The Option III licensing basis is based on the Period Based Detection Algorithm (PBDA), which is applied in both the GE and ABB systems. While there may be small differences between the two systems (e.g., OPRM trip logic and averaging time constant), the two protection systems are equivalent with regard to protecting the MCPR safety limit.

Each OPRM module applies the three separate algorithms for detecting local oscillations described in NEDO-31960-A and NEDO-31960-A, Supplement 1: the period based algorithm (PBA), the amplitude based algorithm (ABA) and the growth rate algorithm (GRA). Each OPRM module executes the algorithms on the LPRM signals and cell configurations for that channel and generates alarms

and trips based on the results. Either module in a channel can trip the OPRM channel. The OPRM trips actuate the RPS when the appropriate RPS trip logic is satisfied.

The HCGS OPRM system setpoints are currently determined utilizing the methods as described in the topical reports identified above and discussed in PUSAR Section 2.4. Therefore, there are no issues related to the interface between the HCGS OPRM hardware and GE methods.

ATWS EPGs

3.43 What version of emergency operating guidelines is currently implemented in Hope Creek? Provide a short description of the process used to ensure that the emergency procedure guideline (EPG) variables (e.g., hot shutdown boron weight (HSBW), heat capacity temperature limit (HCTL) are adequate under CPPU conditions.

Response
BWR Owners' Group (BWROG) Emergency Procedure and Severe Accident Guidelines (EPGs/SAGs), Revision 1, July 1997, is currently implemented at HCGS. The emergency operating procedures (EOPs) are being revised for EPU implementation and will be upgraded to the BWROG EPGs/SAGs Rev. 2, published in March 2001.

When required by changes in plant configuration (as identified by the design change process), changes to Emergency Operating Procedures, including changes to EOP calculations and plant data, are developed and implemented in accordance with plant administrative procedure for EOP program maintenance. Hope Creek performs EOP calculations consistent with the BWR Owners Group EPGs/SAGs Appendix C. Critical software is verified and validated by Design Engineering to generate EOP results. The EOP calculation input and output data is reviewed and verified by Design Engineering. Changes to the EOP calculation outputs are forwarded to Operations for use in revising the EOP Procedures/Flow Charts and the SAGs and supporting documents. Finally the EOP flow charts are verified and validated by Operations, including trial use in the simulator.

ATWS/Stability

3.44 Provide a short description of how the Stability Mitigation Actions (e.g. immediate water level reduction and early boron injection) are implemented in Hope Creek. Does operation at CPPU conditions require modification of any operator instructions?

Response
The ATWS mitigation strategy is based on the BWROG Emergency Procedures Guidelines which are incorporated in the existing HC EOPs (Particularly: HC.OP-EO.ZZ-0101A, ATWS RPV Control and HC.OP-EO.ZZ-0206A, ATWS RPV Flooding). The EOPs have the BWROG EPGs/SAGs strategy that includes reactor water level reduction below the feedwater sparger and immediate boron injection for reactor power levels above 4%.

The EPU implementation does not change operator strategy on ATWS level reduction or early boron injection. Although unrelated to Stability Mitigation, EPU does lower the Boron Injection Initiation Temperature (BIIT) ~10°F at Hope Creek for power levels below 4% due to the greater decay heat as a result of EPU (from 150°F to140°F). That is, before suppression pool reaches BIIT, boron is injected. At Hope Creek when reactor power is above 4% power in an ATWS, there is no change due to EPU and boron is injected immediately.

EPG calculations for EPU implementation are currently under review. The EPU implementation is not expected to change operator strategy on ATWS level reduction or early boron injection. EPU affects some of the calculated curves (see response to RAI 4.1 below), but does not affect stability mitigation actions. The changes due to EPU do not require modification of operator instructions.

Plant-Specific OPRM System

3.45 Hope Creek currently operates under Option III solution. Please provide a clarification for the following areas:

a) Describe the process that was followed by Hope Creek to implement Option III L/T Stability Solution and to verify that Option III is still applicable under CPPU operation.
b) Describe the expected effects of CPPU operation on Option III.
c) Describe any alternative method to provide detection and suppression of any mode of instability other than through the current OPRM scram.
[d) Not used in Reference 2]
e) Provide a summary of the Hope Creek TSs affected by the Option III implementation and future CPPU operation.
f) List the approved methodologies used to calculate the OPRM setpoint by the current operation and future Hope Creek CPPU operation.

Response
Response to Part a
The HCGS Option III L/T Stability Solution was implemented as described in LR N04-0069, LCR H04-02. The reload licensing methodology will be performed in accordance with NEDO-32465-A and the BWROG Plant-Specific Regional Mode DIVOM Procedure Guideline, with the Backup Stability Protection methodology

used if the OPRM system is inoperable. The applicability of Option III to CPPU conditions at HCGS is described in PUSAR Section 2.4.2. Both the Option III amplitude setpoint (and the corresponding Confirmation Count setpoint) and the BSP boundaries will be evaluated for each reload cycle.

Response to Part b
Implementation of CPPU at HCGS will result in operation with the same maximum control rod line as for the current licensed condition (i.e., MELLLA rod line). The limiting condition for stability protection analysis is on the maximum control rod line at low core flow. Therefore, the analysis of OPRM (Option III) related stability protection setpoints for CPPU will be performed at the same conditions (power/flow) as for the current licensed condition. The generic analysis for the Option III Hot Channel Oscillation Magnitude (HCOM) and the OPRM hardware were designed to be independent of core power. Although the flatter power profile in EPU core designs would tend to result in smaller HCOM values, the existing HCOM conservatism has been retained for application to EPU. All things being equal, the CPPU core might result in a lower OPRM amplitude setpoint due to a slightly higher peak bundle power. However, as is noted above, the OPRM amplitude setpoint is evaluated for each reload cycle and any setpoint change as a result of EPU and/or core design will be reflected in the actual plant settings.

Response to Part c
Alternate methods for detecting and suppressing core thermal hydraulic instabilities have been established for HCGS. These methods are implemented if it has been determined that a common mode deficiency exists in the OPRM System that has rendered the OPRM system inoperable, as required by HCGS TS 3.3.11. The alternate method consists of the application of a Backup Stability Solution (BSP) operations strategy. The BSP strategy, which will remain in effect until the OPRM System has been returned to operable status, contains actions similar to The Interim Corrective Actions (ICAs) as published by the BWR Owners Group (BWROG-94078).

The BSP strategy maintains similar guidance on how and when to monitor for THI, and contains detailed power-to-flow operating maps that depict "Immediate Exit" and "Immediate Scram" regions of high power and low flow to enable manual operator actions for preventing plant operation in areas where the potential for THI is increased.

An evaluation describing the calculation of the BSP region boundaries has been provided in NEDC-33179-R1, "BSP Evaluation Report MELLLA Backup Stability Protection Evaluation for Hope Creek Cycle 14 at CPPU Conditions."

Response to Part d
N/A

Response to Part e
The Hope Creek Technical Specifications affected by the implementation of the Option III stability solution are described in (LR N04-0069, LCR H04-02). Implementation of CPPU at HCGS will impact only the Technical Specification defined OPRM trip-enabled region boundary for power as described in PUSAR Section 2.4.2. This CPPU related change maintains the same absolute power region boundary as for CLTP operation.

Response to Part f
The approved methods for the determination of the OPRM setpoints are identified in NEDC-33186P, Revision 1, "MELLLA TRACG DIVOM Evaluation for Hope Creek at CPPU Conditions" and NEDO-33188, "MELLLA Option III Stability Evaluation for Hope Creek at CPPU Conditions." These methods are unchanged from the current licensed methods applied at HCGS. Both methods are based on NEDO-32465-A and the BWROG plant specific DIVOM Procedure Guideline.

Hot Channel and Core-Wide Decay Ratio

3.46 Provide a table of hot channel and core-wide decay ratios at the most limiting state point for the last cycles and the proposed CPPU condition. The purpose is to evaluate the impact of CPPU on relative stability of the plant, and the applicability of Option III to Hope Creek under these new conditions.

Response
As part of the reload licensing process, the current NRC-approved Option III methodology does not require an ODYSY evaluation at the limiting power/flow point.

In lieu of decay ratios at the limiting power/flow state point, the Backup Stability Protection (BSP, Reference 3.46-1) state point analysis results are provided.

The BSP results for Cycle 14 and the EPU equilibrium core are presented below. The key parameters for these two cycles are shown in Table 3.46-1.

Tables 3.46-2 and 3.46-3 list the core and hot channel decay ratios for two state points (A_1-ICA and B_1-ICA) for both EPU and Cycle 14 (Pre-EPU), respectively. The two state points are evaluated based on the scram region methodology outlined in Reference 3.46-1. The Cycle 14 (Pre-EPU) and EPU results are found to be comparable in terms of core decay ratios. The Cycle 14 (Pre-EPU) channel decay ratios are in general higher due to a very conservative treatment of the SVEA 96+ channels in the GE model. The hot channel ratios are expected to improve for EPU as more SVEA 96+ fuel bundles are replaced by GE14 fuel bundles.

The response to RAI 3.45 addresses the applicability of Option III to Hope Creek under the new EPU conditions.

References

3.46-1 OG 02-0119-260, GE to BWR Owner's Group Detect and Suppress II Committee, "Backup Stability Protection (BSP) for Inoperable Option III Solution," July 17, 2002.

3.46-2 GE-NE-0000-0044-3736-R0, "MELLLA Backup Stability Protection Evaluation for Hope Creek Cycle 14," January 2006.

Table 3.46-1 Key Parameters for Cycle 14 and EPU Cycle

Parameter	Cycle 14*	EPU Cycle
Core loading (fuel bundles)	444 SVEA96+, 320 GE14	Equilibrium GE14 (764 bundles)
Fresh Fuel	GE14	GE14
Cycle Exposure (MWD/ST)	11730	12,063
Rated Power	3339 MWt (101.4% OLTP)	3840 MWt (116.6% OLTP)
Rated feedwater temperature	422.6 ° F	431.6 °F
Reduced feedwater temperature used in the stability analysis	400.0 °F	409.0°F

* Reference 3.46-2

Table 3.46-2 EPU Decay Ratios at the BSP and ICA Scram Region Points with a Bounding Feedwater Temperature of 409.0°F (Rated Power = 3840 MWt)

Point	Exposure	Flow	EPU Power (%)	Pre-EPU Power (%)	Flow (%)	Core DR	Highest Channel DR
A_1	EOC	HFCL	56.9	65.4	38.4	0.800	0.501
A_1-ICA	EOC	HFCL	58.2	66.9	40.0	<0.800	<0.501
B_1	EOC	NCL	48.8	56.1	34.4	0.799	0.477
B_1-ICA	EOC	NCL	44.7	51.4	35.0	<0.799	<0.477

Table 3.46-3 Cycle 14 (Pre-EPU) Decay Ratios at the ICA Scram Region Points with a Bounding Feedwater Temperature of 400.0°F (Rated Power = 3339 MWt)**

Point	Exposure	Flow	EPU Power (%)	Pre-EPU Power (%)	Flow (%)	Core DR	Highest Channel DR
A_1-ICA	EOC-1000	HFCL	N/A	66.9	40.0	0.785	0.688
A_1-ICA	BOC	HFCL	N/A	66.9	40.0	0.469	0.813
B_1-ICA	EOC	NCL	N/A	51.4	35.2	0.622	0.497
B_1-ICA	BOC	NCL	N/A	51.4	35.2	0.250	0.576

** From Reference 3.46-2. All cases are based on a Haling depletion exposure projection wrapup with the exception of the BOC case, which is based on a rodded wrapup.

4) Operator Lic & Human Performance Branch (IOLB)

4.1 Describe any changes to abnormal operating procedures (AOPs) and emergency operating procedures (EOPs) as a result of the proposed EPU.

Response
The planned changes to the abnormal operating procedures (AOPs) and emergency operating procedures (EOPs) are prepared in accordance with the PSEG plant procedure control and training processes.

The following AOPs are being changed for Extended Power Uprate (EPU) implementation:

- HC.OP-AB.BOP-0001, Feedwater Heating: Power limits for feedwater heaters out of service and feedwater temperature values and limits are being changed.
- HC.OP-AB.BOP-0002, Main Turbine: Some references to power level are being changed for shutdown actions.
- HC.OP-AB.BOP-0004, Grid Disturbance: Power level is being changed for shutdown actions similar to HC.OP-AB.BOP-0002 above.
- HC.OP-AB.BOP-0006, Main Condenser Vacuum: The offgas flow limit is being changed to allow for increased gas generation at EPU.
- HC.OP-AB.RPV-0003, Recircirculation System/Power Oscillation: The Power-Flow Map is being revised and the power level entry condition is being changed.
- HC.OP-AB.RPV-0004, RPV Level Control: Operational power levels are being lowered for primary condensate, secondary condensate, and feedwater pumps out of service.

Changes to the EOPs consist of revisions to numerical values to account for increased decay heat due to EPU. Changes to EOPs for EPU implementation include:

- Heat Capacity Temperature Limit (HCTL) curves are lowered
- Pressure Suppression Pressure (PSP) limit curve is lowered
- Boron Injection Initiation Temperature (BIIT) value is lowered
- Decay Heat Removal Pressure (DHRP) value is raised

Although not required for EPU implementation, PSEG also plans to update the Hope Creek EOPs and SAGs to incorporate Revision 2 to the BWR Owners' Group (BWROG) Emergency Procedure and Severe Accident Guidelines (EPGs/SAGs) when EPU is implemented.

a) Include any changes to setpoints and alarms that will be incorporated into operating procedures and training materials as a result of the proposed EPU.

Response
Technical Specification setpoint changes associated with EPU implementation are identified in Table 1 of Attachment 1 to PSEG's request for license amendment (Reference 1). Other setpoint and alarm changes are listed in Table 5-3 of NEDC-33076P, Revision 2 (Atttachment 4 to Reference 1). Affected operating procedures, including AOPs and EOPs are being revised in accordance with the design change process. Associated lessons plans will be updated and revised to reflect the plant modifications and procedure changes associated with the EPU.

b) Describe any procedural changes that credit manual actions due to the EPU that are not currently credited in the Final Safety Analysis Report (FSAR).

Response
There are no procedural changes that involve new manual actions due to EPU. The analysis for EPU credits existing manual actions following the same time limits currently credited in the Updated Final Safety Analysis Report (UFSAR). The post-EPU manual actions are those currently required by existing operating procedures.

Time critical manual operator actions credited in the UFSAR include:

- The containment analysis assumes operator action at 10 minutes after the postulated recirculation line break accident to manually align an RHR System Heat Exchanger for core or containment cooling.
- In the Instrument Line Break Accident analysis the operator will initiate depressurization at 10 minutes after the break.
- The Loss of Shutdown Cooling evaluation assumes operator action beginning at 10 minutes to establish a shutdown cooling path for the vessel.

c) If any changes are identified, describe how these changes may affect operator action response times credited in the safety analyses in the UFSAR.

Response
As discussed above, the operator action response times credited in the safety analyses in the Updated Final Safety Analysis Report (UFSAR) are not changed by EPU.

4.2 Identify and describe the effect on manual actions sensitive to the proposed EPU that are credited in the safety analyses in the UFSAR.

Response
Hope Creek was designed to mitigate the consequences of design basis accidents automatically with a minimum of manual operator actions. Most safety systems were designed to rely on automatic system actuation to ensure that the safety systems are capable of carrying out their intended functions. The operator is relied upon to observe and verify automatic actions. In a few cases, limited operator actions are credited in the analyses as indicated in 4.1.b above. There is no effect on manual operator actions credited in the safety analyses in the Updated Final Safety Analysis Report (UFSAR) due to EPU. A discussion of these time critical manual actions is in the response to 4.1.b above.

a) If any manual actions are affected, has the licensee performed an evaluation of the environment of the manual actions for the applicable accident scenarios?

Response
No manual operator actions credited in the safety analysis in the UFSAR are affected by EPU as discussed above (4.1.b).

b) If any manual actions are affected, describe how the EPU affects the amount of available time for the operators to perform their tasks.

Response
No time critical manual actions credited in the safety analysis in the UFSAR are affected by EPU as discussed above (4.1.b).

c) How will the EPU affect the actual time for the operators to perform their tasks during accident scenarios?

Response
The actual tasks performed by operators are not changed by EPU. The greater amount of decay heat due to EPU will affect the operator time associated with decay heat removal results only. The Hope Creek simulator will be modified for EPU changes in decay heat generation and licensed operators will be trained and evaluated on these effects.

d) The staff requests the current amount of time available and the post-EPU times for the operators to perform their actions provided in the EOPs and AOPs. In the response, include a discussion of how the new times will be validated to ensure that operators have enough time to perform the actions affected by the EPU.

Response

The Emergency Operating Procedures (EOPs) are symptom based procedures. They are used for events beyond design basis accidents and do not have specific, documented time constraints or limitations, due to the variability of failure magnitude and equipment loss that are comprehensively covered by these procedures.

The Abnormal Operating Procedures (AOPs), are not purely symptom based, and have some time-critical operator actions. Technical Specifications drive most of the time-critical actions in the AOPs, and the most limiting action is when a Safety Relief Valve (SRV) is stuck open, there is a two minute time limit in Technical Specification 3.4.2.1.b to place the reactor mode switch in the Shutdown position.

Other examples of Technical Specification driven AOP actions include:

- Post- SRV opening- documentation of suppression pool temperatures- operating, >95 degrees (60 minutes)
- Post- SRV opening- documentation of suppression pool temperatures- shutdown, >95 degrees (30 minutes)
- Post- SRV opening- performance of Torus Vacuum Breaker operability surveillances (12 hours)
- Loss of shutdown cooling- documentation of temperatures (1 hour)
- Loss of shutdown cooling- restoration of forced circulation (1 hour)

These time requirements are not affected by the EPU.

Reactor water chemistry guidelines for conductivity are contained in the AOPs and have threshold values with reactor shutdown time criteria (most limiting time is 6 hours to commence an orderly shutdown); the action times are based on leak severity, and are not affected by the EPU.

Guidance for Loss of Power events is contained in the AOPs and there is one action with a time limitation of 30 minutes for direction of field technician actions to reduce heat loads within control systems by de energizing non-essential loads and blocking open panels and doors to promote heat removal; these actions are not affected by the EPU.

In other cases, the procedures are designed so that the severity of the event dictates the time available for response, ranging from Immediate Operator Actions to more long range corrective actions.

4.3 Identify and describe any changes to human interfaces for control room controls, displays, and alarms that will affect the operator's ability to interpret, read or visually identify the information required from the instrumentation.

Response
For EPU, impact to the control room human-machine interfaces (HMIs) is minimal. There are no changes to human interfaces that will affect the operator's ability to interpret, read or visually identify the information required from the instrumentation. The HMIs for the main plant computer Control Room Integrated Display System (CRIDS) and Safety Parameter Display System (SPDS) are not affected by EPU.

The planned changes to the control room are prepared in accordance with the plant Design Change Process (DCP). Under this process, a Human Factors engineering review is performed for changes associated with the HCGS control room design review. The change control process also requires an impact review by operation and training personnel. Results of the reviews were incorporated in the design change package. Training and implementation requirements are also identified and tracked, including simulator impact.

Prior to EPU implementation, the operators will be trained using operating procedures, abnormal procedures, aids, charts, and training simulator updated for EPU conditions. These engineering reviews and operator training requirements discussed in section 10.6 of NEDC-33076P, Revision 2 (Atttachment 4 to Reference 1) are key elements to ensure that the operator's ability to interpret, read or visually identify the information required from the instrumentation is not impacted.

a) Describe any controls, displays, alarms that may be upgraded from analog to digital as a result of the proposed EPU and how operators will be tested to determine proficiency.

Response
As part of the plant modification to upgrade the Low Pressure Turbine to support EPU power level, the HCGS turbine control system (EHC) has been upgraded to a GE Mark VI Digital Electro-Hydraulic Control (DEHC) system. DEHC has been implemented in the plant and operational since RF12 (December 2004).

The DEHC design changes were also prepared under the plant DCP process. For analog to digital upgrades, additional design requirements

were imposed which included Human Factors Engineering, Software Quality requirements, and EMI/RFI compatibility reviews. The analog EHC HMI was replaced with a touchscreen control panel. To provide the operators with the familiarity and proficiency on the operational use of the DEHC HMI and control features, the HCGS training simulator was upgraded with the same Mark VI DEHC system. Operator Training was then performed in the training simulator prior to placing the plant DEHC into operation.

Operational and written tests are conducted as part of the two year operator re-qualification program; topics for testing may include design and operation of the DEHC system.

4.4 In the submittal, the licensee stated that the Safety Parameter Display System (SPDS) will be reviewed to determine effects from the EPU. Please describe any changes to the SPDS that have been identified thus far including monitored points, alert and trip set points, and various changes in EOP curves and limits.

Response

The Hope Creek Safety Parameter Display System displays data for Critical Safety Functions (CSFs). The CSFs and associated parameter inputs are not affected by EPU. Therefore, the information presented on the SPDS Top Display and the method of presentation remain the same as before EPU. There are minor re-scaling changes to input/output feedwater parameters to support the new span changes required for EPU.

The HCGS SPDS system also provides a procedure-based display concept to support the execution of the HCGS EOPs. In conjunction with changes required for EPU operation and EPG/SAG Rev. 2, the following SPDS EOP curves are impacted and will be revised for EPU implementation:

- Pressure Suppression Pressure (PSP)
- Heat Capacity Temperature Limit (HCTL)
- Drywell Spray Initiation Pressure Limit (DSIPL)

The Power to Flow map (PFM) display, an ancillary SPDS display to aid the operators during normal plant operation, will be changed to reflect EPU conditions.

4.5 Provide the implementation schedule for making the changes to the operator training program and the plant referenced control room simulator.

Response

The EPU operator training is scheduled to start in training segment 2 (end of first quarter of 2007) and continue through cycle training segment 6 (beginning of third quarter 2007). The EPU operator training will consist of combined classroom and simulator training with the training scope described in PUSAR section 10.6 (Operator Training and Human Factors).

Updates and validation of the training simulator changes required for EPU, which include the THOR-Balance of Plant (THOR-BOP) model, Turbine, Digital Electro Hydraulic Controls (DEHC) and Core Model changes have been completed and will be used for scheduled EPU operator training.

There are some minor changes to the simulator (Plant computer, Safety Parameter Display System (SPDS), meter scaling, and Digital Feedwater System) that were originally scheduled before EPU implementation and are now scheduled in the 4th quarter 2007, after the completion of the scheduled HCGS simulator relocation. The need to maintain training configuration during the administration of HCGS ILOT training and examinations and conflict with the scheduled HCGS simulator relocation make it necessary to make the simulator changes listed above after EPU implementation. Nonetheless, the operators will be trained with these changes prior to EPU implementation during the scheduled classroom operator training.

References

1. PSEG letter LR-N06-0286, Request for License Amendment: Extended Power Uprate, September 18, 2006

2. NRC letter, Hope Creek Generating Station - Request for Additional Information Regarding Request for Extended Power Uprate (TAC NO. MD3002), February 16, 2007