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PSEG
Nuclear LLC

10 CFR 50.90

LR-N07-0060
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March 30, 2007

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, March 2, 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.

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.

There are no regulatory commitments contained within this letter

A001

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). Affidavits supporting this request are 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 3/30/07
(date)

Sincerely,

George P. Barnes
Site Vice President
Hope Creek Generating Station

Attachments (4)
1. Response to Request for Additional Information (proprietary)
2. Response to Request for Additional Information (non-proprietary)
3. Calculation No. SC-SE-0002-2, "Average Power Range Monitor (APRM) Channels A-F and Rod Block Monitors (RBM) Channels A and B"
4. Calculation No. SC-SM-0001-1, "Main Steam Line High Flow to NS4 Isolation Logic"

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

PROPRIETARY INFORMATION NOTICE

This enclosure contains proprietary information of the General Electric Company (GE) and is furnished in confidence solely for the purpose(s) stated in the transmittal letter. No other use, direct or indirect, of the document or the information it contains is authorized. Furnishing this enclosure does not convey any license, express or implied, to use any patented invention or, except as specified above, any proprietary information of GE disclosed herein or any right to publish or make copies of the enclosure without prior written permission of GE. The header of each page in this enclosure carries the notation "GE Proprietary Information."

The GE proprietary information is identified by [[double underlines inside double square brackets{3}]]. The superscript notation{3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

General Electric Company

AFFIDAVIT

I, George B. Stramback, state as follows:

(1) I am Manager, Regulatory Services, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in Enclosure 1 of the GE-HCGS-EPU-665, Edward D. Schrull (GE) to Larry Curran (PSEG), *Transmittal - Response to Request for Additional Information (RAI) Regarding Amendment Application for Hope Creek Generating Station Extended Power Uprate – RAI 3.47*, GE Proprietary Information, dated March 28, 2007. The Enclosure 1 (*GE Response to NRC RAI 3.47*) proprietary information is delineated by a double underline inside double square brackets. Figures and large equation objects are identified with double square brackets before and after the object. In each case, the superscript notation[{3}] refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

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

(4) Some examples of categories of information which fit into the definition of proprietary information are:

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

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

c. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, resulting in potential products to General Electric;

d. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

The information sought to be withheld is considered to be proprietary for the reasons set forth in paragraphs (4)a., and (4)b, above.

(5) To address 10 CFR 2.390 (b) (4), the information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GE, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GE, no public disclosure has been made, and it is not available in public sources. All disclosures to third parties including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in paragraphs (6) and (7) following.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge. Access to such documents within GE is limited on a "need to know" basis.

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

(8) The information identified in paragraph (2), above, is classified as proprietary because it contains detailed information about the results of analytical models, methods and processes, including computer codes, which GE has developed, obtained NRC approval of, and applied to perform evaluations of loss-of-coolant accident events in the GE Boiling Water Reactor ("BWR"). The development and approval of the BWR loss-of-coolant accident analysis computer codes was achieved at a significant cost to GE, on the order of several million dollars.

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

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

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GE.

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.

GE's competitive advantage will be lost if its competitors are able to use the results of the GE experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

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

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

Executed on this 28th day of March 2007.

George B. Stramback
General Electric Company

General Electric Company

AFFIDAVIT

I, George B. Stramback, state as follows:

(1) I am Manager, Regulatory Services, General Electric Company ("GE") and have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in Enclosure 1 of the GE-HCGS-EPU-662, Edward D. Schrull (GE) to Larry Curran (PSEG), *Transmittal - Response to Request for Additional Information (RAI) Regarding Amendment Application for Hope Creek Generating Station Extended Power Uprate - RAIs 3.48 thru 3.55*, GE Proprietary Information, dated March 27, 2007. The Enclosure 1 (*GE Responses to NRC RAIs 3.48 thru 3.55*) proprietary information is delineated by a double underline inside double square brackets. Figures and large equation objects are identified with double square brackets before and after the object. In each case, the superscript notation{3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

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

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c. Information which reveals aspects of past, present, or future General Electric customer-funded development plans and programs, resulting in potential products to General Electric;

d. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

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

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

Executed on this 26th day of March 2007.

George B. Strámback
General Electric Company

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. Each NRC question is restated below followed by PSEG's response.

9) PRA Licensing Branch (APLA)

9.1 Based on the Hope Creek Power Uprate Safety Analysis Report (PUSAR), Section 10.5, Pages 10-9 and 10-10: The NRC staff infers that a complete Level 2 probabilistic risk assessment (PRA) exists for the constant pressure power uprate (CPPU) plant and the current licensed thermal power (CLTP) plant. The NRC staff observes that a complete Level 2 PRA is different (i.e., more detailed) than a simplified PRA model used to estimate large early release frequency (LERF), e.g., NUREG/CR-6595. Please confirm that the NRC staff's inference is correct. If the NRC staff's inference is correct, please provide a summary of the Level 2 PRA results for both the CPPU and CLTP plants that includes a breakdown by release type (LERF, large late releases, core-damage events that do not result in any release, etc.).

Response
The Hope Creek Generating Station (HCGS) Level 2-LERF PRA model quantifies the LERF end state only. The Level 2 PRA does not evaluate a full range of radionuclide release end states (e.g., LERF, large late releases, etc.). Therefore, a summary by release type cannot be readily provided. The results for the "LERF" and "Non-LERF" end states are as follows:

End State	CPPU (/yr)	CLTP (/yr)
LERF	2.96E-7	2.35E-7
Non-LERF	9.80E-6	9.23E-6
Total	1.01E-5	9.46E-6

The HCGS Level 2-LERF PRA incorporates an integrated Level 1 and Level 2 PRA model with the end states of LERF and Non-LERF. Level 1 core damage scenarios are propagated into individual Level 2 Containment Event Trees (CETs) based on the Level 1 core damage accident class end states.

The Level 2-LERF CET models the containment response accident progression. The HCGS Level 2-LERF model is a plant specific integrated model and is more detailed than the methodology provided in NUREG/CR-6595. Examples of the differences in the methods are included in Table 9.1-1.

Table 9.1-1

COMPARISONS OF THE SIMPLIFIED NUREG/CR-6595 LERF METHODOLOGY WITH THE LEVEL 2-LERF METHOD USED FOR HCGS

Example Modeling Differences	HCGS Level 2-LERF Model	NUREG/CR-6595
Integrated Level 1 – Level 2 Model	Yes	No
Dependencies explicitly carried through Level 1 and Level 2 and treated by the Boolean logic	Yes	No
Level 2 branch probabilities determined using fault trees that are integrated into the CAFTA model	Yes	No
Human Reliability Analysis (HRA): Explicitly modeled to account for dependencies on Level 1 sequences	Yes	No
Plant specific Thermal Hydraulic Analysis	Yes	No

9.2 In the Hope Creek PUSAR, Section 10.5, Pages 10-9 and 10-10: It is stated that the change in LERF is primarily due to the change in core damage frequency (CDF). Please provide the definition of LERF used in the PRA, specifically discussing the distinction between an early release and a late release. In addition, confirm that none of the late releases were reclassified as early releases as a result of the proposed EPU.

Response

The Large Early Release Frequency is defined as follows:

- RG 1.174 states that:

  "LERF is being used as a surrogate of the early fatality QHO. It is defined as the frequency of those accidents leading to significant, unmitigated releases from containment in a time frame prior to effective

> evacuation of the close-in population such that there is a potential for early health effects. Such accidents generally include unscrubbed releases associated with early isolation (failure) [sic]".

- The ASME PRA Standard states:

> "*large early release:* the rapid, unmitigated release of airborne fission products from the containment to the environment occurring before the effective implementation of off-site emergency response and protective actions such that there is a potential for early health effects."
>
> *"large early release frequency (LERF):* expected number of large early releases per unit of time."

As can be seen, the definition of LERF includes the consideration of both the time available for actions to protect the public and the magnitude of the release.

The following describes how this definition is implemented in the HCGS PRA model.

- Level 2 release categories are defined based on two parameters: timing (of the initial radionuclide release) and severity (i.e., radionuclide release magnitude).
- Timing of the release for each sequence is based on plant specific thermal hydraulic calculations of the sequence chronology.
- The classification of release magnitude is based on a review of industry studies and use of Reference [9.2-1].

To meet the definition of LERF provided in Reg Guide 1.174, the Hope Creek Level 2 model defines LERF as radionuclide releases that are:

- "Early" in timing (i.e., less than 6 hours after the initiating event)
- "High" in severity (i.e., greater than 10% CsI fraction).

In addition, a review of the Hope Creek Level 2 LERF end states confirms that none of the late releases were reclassified as early releases as a result of the proposed EPU.

<u>Release Magnitude Bins</u>

The quantification of the source terms associated with the radionuclide release severity categories was accomplished through Hope Creek specific thermal

hydraulic calculations. In order to help define the severity classifications, it was necessary to identify a common factor that could be used to allow the results of consequence analyses from different studies to be used in this study. A review of previous studies revealed an assumption that could be made relating release characteristics based on CsI release fraction to off-site consequences.

Reference 9.2-1 documents the results of an analysis of the conditional mean number of early fatalities as a function of the CsI release fraction. Using the insights from Reference 9.2-1, a "High" magnitude release is a fractional release of CsI fission products greater than 10%.

This relationship allows the use of results of many consequence analyses in providing source terms from the breadth of release paths analyzed in this study. The plant specific influences on each sequence source term as affected by the various release paths are accounted for in the deterministic calculations to support the assignment of release severity to each of the sequences.

Timing

The plant's Emergency Plan includes Emergency Action Levels (EALs) that specify, among other things, the symptoms under which a General Emergency would be declared. The General Emergency Action Level is used as the trigger for interaction and is generally considered to occur near the time of initial perturbation, i.e., within approximately 20-30 minutes except for certain loss of decay heat removal accident sequences.

The General Emergency declaration and the evacuation of the public are part of the Emergency Planning process. Both are critical to the assessment of whether the time available for protective actions is sufficient to prevent a LERF.

The declaration of a General Emergency is used in this analysis to set the initial time of the clock to initiate the public protective actions. Therefore, the times cited here for the determination of radionuclide release bins are relative to the declaration of a General Emergency. This declaration is sequence dependent. The Hope Creek plant specific Emergency Action Levels (EALs) were reviewed to ensure that a General Emergency would be declared soon after the initiating event. For sequences where declaration of the General Emergency could be delayed (e.g., certain loss of decay heat removal events), the Hope Creek EALs ensure that a General Emergency is declared sufficiently early to support the conclusion that these scenarios do not contribute to the LERF end state.

The HCGS evacuation study considers variations in season, time of day, and weather.

The HCGS evacuation can be accomplished under worst case conditions within 210 min. following declaration of the General Emergency. The General Emergency declaration is controlled by the Emergency Coordinator and the specific Emergency Action Levels associated with accident symptoms.

Key to the assessment of timing necessary for a LERF are the following:

a) the cue for initiating the General Emergency declaration
b) the evacuation time
c) the accident sequence timing

Reference

9.2-1 G.D. Kaiser, *Implication of Reduced Source Terms for Ex-Plant Consequence Modeling and Emergency Planning*, Nuclear Safety, Volume 27, Number 3, July-September 1986

9.3 In the Hope Creek PUSAR, Section 10.5, Page 10-13: It is stated that the proposed power uprate would increase the reactor thermal power from 3339 MWt to 3840 MWt, which is approximately a 15% increase in thermal power. However, it is further stated that the CPPU PRA is based on an assumed 20% increase in thermal power. In addition, Page 10-20 and Table 10-10 indicate that calculations performed to estimate the timing of some operator actions were based on a decay heat that is 12.3% greater than original licensed thermal power (OLTP). Please explain why different thermal power levels were used as inputs to the PRA. Justify the use of the 12.3% increase in decay heat, which is lower than the proposed EPU and, therefore, non-conservative.

Response

While calculations performed to estimate the timing of some operator actions were based on a decay heat that is 12.3% greater than OLTP, reevaluation of the associated human error probabilities shows that they are best estimates, accurately reflecting the change in power level for CPPU.

The proposed Hope Creek power uprate would increase the reactor thermal power from 3339 MWt (CLTP) to 3840 MWt (CPPU), which is approximately a 15% increase in thermal power. The thermal hydraulic runs to support the CPPU PRA were performed using a thermal power of 3952 MWt, which is approximately a 20% increase over the original licensed thermal power (OLTP) of 3293 MWt (and approximately a 18.4% increase over the CLTP). It is noted that the CLTP of 3339 MWt is the result of a previous 1.4% uprate from the OLTP of 3293 MWt.

The Hope Creek CPPU PRA and its supporting thermal hydraulic runs are based on 120% of the OLTP. Per the Hope Creek PUSAR, Section 1.2.3, plant safety and operability evaluations may be dispositioned "based on a 120% of OLTP

increase and are bounding for the requested 115% of the CLTP uprate". The Hope Creek CPPU PRA thermal hydraulic runs, which are based on 120% of OLTP, are judged to be bounding and conservative for the CPPU submittal. The CPPU PRA is based on 120% of the OLTP unless stated otherwise (e.g., for specific Human Reliability Analysis timing evaluations).

The reference to "decay heat 12.3% greater than OLTP" for calculating the timing of specific operator actions is based on PSEG calculation BC-0052(Q), Rev. 2, "Plant Cooldown Using One RHR Heat Exchanger." BC-0052(Q), Rev. 2 was the latest available decay heat calculation at the time to support the PUSAR HRA development for the identified operator actions. BC-0052(Q), Rev. 2 was evaluated using a decay heat level 112.3% of OLTP, or 3700 MWt.

Calculation BC-0052(Q) has been updated to Rev. 3 to specifically address the CPPU configuration. BC-0052(Q), Rev. 3 is evaluated using a decay heat level 102% of CPPU, or 3917 MWt. However, BC-0052(Q), Rev. 3 was not available at the time for the deterministic calculations used to support the HRA development for the PUSAR.

The HEP calculations have since been re-evaluated using the BC-0052(Q), Rev. 3 input to derive the HEPs for the CPPU configuration and pre-EPU configuration. These calculations have shown that the HEPs used in the original PUSAR analysis resulted in conservative calculations of the change in risk metric due to overestimation of the change in HEP values. A conservatism removed from the HEP calculation involved the time to the cue for the operator action timing. The time to the cue has been decreased for the CPPU configuration compared to the pre-EPU configuration due to the higher decay heat level. Therefore, as a result of the changes from CLTP to CPPU, the newly derived HEPs, the HEP changes, and the risk changes used in the PUSAR are now considered best estimates and accurately reflect the change in power levels, i.e., much of the conservatism has been eliminated from the calculations.

9.4 In the Hope Creek PUSAR, Section 10.5.3, Page 10-19: It is stated that "...changes in the response of the SACS system (the intermediate safety system cooling loops) were evaluated as they influence crew actions." These changes are not described in Pages 10-11 through 10-13. Please describe what changes have been (or will be) made to the SACS system, and how these changes have been reflected in the PRA.

<u>Response</u>
On Page 10-19, the statement *"...changes in the response of the SACS system..."* refers to revised Hope Creek engineering calculations associated with the change in power level and the resulting impact on the decay heat removal timing of the SACS system. The statement is not meant to reference any hardware or thermal hydraulic capacity changes to the SACS system, but rather

how the new engineering calculations affected the time available for crew responses.

The revised engineering calculations to support the increase in power level are reflected in decreased times to perform operator actions in the PRA related to the SACS system response. Specific SACS related operator actions that are impacted include the following:

- SACS Heat Load Manipulation (Basic event SAC-XHE-FO-HEAT).
- Dependent combination of operator action SAC-XHE-FO-HEAT, failure of SACS heat load manipulation, and Operator Action SWS-XHE-FO-2355A, Failure to Open SACS-SW Heat Exchanger Valve 2355A Locally (Basic event SAC-XHE-FO-HEA5A).
- Dependent combination of operator action SAC-XHE-FO-HEAT, failure of SACS heat load manipulation, and Operator Action SWS-XHE-FO-2355B, Failure to Open SACS-SW Heat Exchanger Valve 2355B Locally (Basic event SAC-XHE-FO-HEA5B).

Additional information regarding the above operator actions is provided in PUSAR Section 10.5.3 (e.g., Table 10-10) and the response to RAI 9.7.

9.5 In the Hope Creek PUSAR, Section 10.5.3, Page 10-20: It is stated that, in general, the cognitive portions of the post-initiator human error probabilities (HEPs) were estimated using the Cause-Based Decision Tree Method (CBDTM). However, it is further stated that some post-initiator HEPs were estimated using a combination of the CBDTM and the Accident Sequence Evaluation Program (ASEP) time reliability correlation. What criteria or guidelines were used to determine the appropriate human reliability quantification method to be used for each HEP?

Response

Due to the time constraints on accomplishing some operator actions, these post-initiator HEPs were calculated using a combination of the CBDTM and the ASEP TRC for determining the cognitive portions of the HEPs. The time dependent non-response (i.e., cognitive) probabilities from the ASEP methodology are applied according to its basic principles for short term actions (e.g., time available for diagnosis <1 hour) in order to compensate for possible non-conservative estimates produced by the CBDTM methodology. The total non-response probability for short term action is taken to be the sum of the CBDTM and ASEP results; the ASEP component is found to be a negligible contributor for longer term actions. Examples

of post-initiator HEPs that were calculated using a combination of the CBDTM and ASEP include the following:

- Failure to Depressurize with SRV w/o High Pressure Injection (Basic event NR-U1X-DEP-SRV). The pre-EPU time available for this action is 46 minutes. The EPU time available for this action is 40 minutes. This operator action is identified in Table 10-10 of the PUSAR.

- SACS Heat Load Manipulation (Basic event SAC-XHE-FO-HEAT). The pre-EPU time available for this action is 33 minutes. The EPU time available for this action is 27 minutes. This operator action is identified in Table 10-10 of the PUSAR.

The EPRI Cause-Based Decision Tree Method (CBDTM) (Reference 9.5-1) as implemented by the EPRI HRA Calculator has been chosen as the primary basis for determining the cognitive diagnosis portions of the HEPs for the Hope Creek HRA. The execution error is derived using the NUREG/CR-1278 (Reference 9.5-2) HRA procedure called Technique for Human Error Rate Prediction (THERP) as it is implemented in the EPRI HRA Calculator. (See the response to RAI 9.6 for further discussion of the THERP HRA methodology.)

The NRC in NUREG-1842 (Reference 9.5-3) has identified the potential weakness of the CBDTM associated with its weak correlation with the applied stress due to time constraints on the action. ["There is no guidance for using the method under time-limited conditions, for it was not intended to address such situations."]

Based on this NRC insight, the CBDTM method is supplemented with a recognized method, the Accident Sequence Evaluation Program (ASEP) Time Reliability Correlation (TRC) (Reference 9.5-2) to better model and account for the effects of time constraints on the Human Error Probability (HEP) assessment. There are only a few exceptions to the use of the calculator. These exceptions still utilize the Cause Based Method and THERP but implement them outside of the EPRI HRA calculator so that the time performance shape factor (PSF) can be accounted for quantitatively.

References

9.5-1 Parry, G. W., An Approach to the Analysis of Operator Actions in Probabilistic Risk Assessment, EPRI TR-100259, June 1992.

9.5-2 Swain, A.D., Guttmann, H.E., Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Applications, NUREG/CR-1278, August 1983.

9.5-3 A. Kolaczkowski, Evaluation of Human Reliability Analysis Methods Against Good Practices, NUREG-1842, September 2006.

9.6 In the Hope Creek PUSAR, Section 10.5.3, Page 10-20: What method was used to estimate the implementation portion of the post-initiator HEPs?

Response

For the Hope Creek HRA, the implementation portions of the post-initiator HEPs (i.e., the execution error) is derived using the NUREG/CR-1278 (Reference 9.6-1) HRA procedure called Technique for Human Error Rate Prediction (THERP) as it is implemented in the EPRI HRA Calculator.

The basic THERP process is outlined in Figure 9.6-1. Each operator action execution failure probability is developed in the Hope Creek HRA document as supported by the HRA Calculator. The sensitivity analysis, which is part of Phase 4 (see Figure 9.6-1), has been performed using the complete HEPs (P_{COG} + P_{EXE}).

Reference

9.6-1 Swain, A.D., Guttmann, H.E., Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Applications, NUREG/CR-1278, August 1983.

OUTLINE OF A THERP PROCEDURE FOR HRA

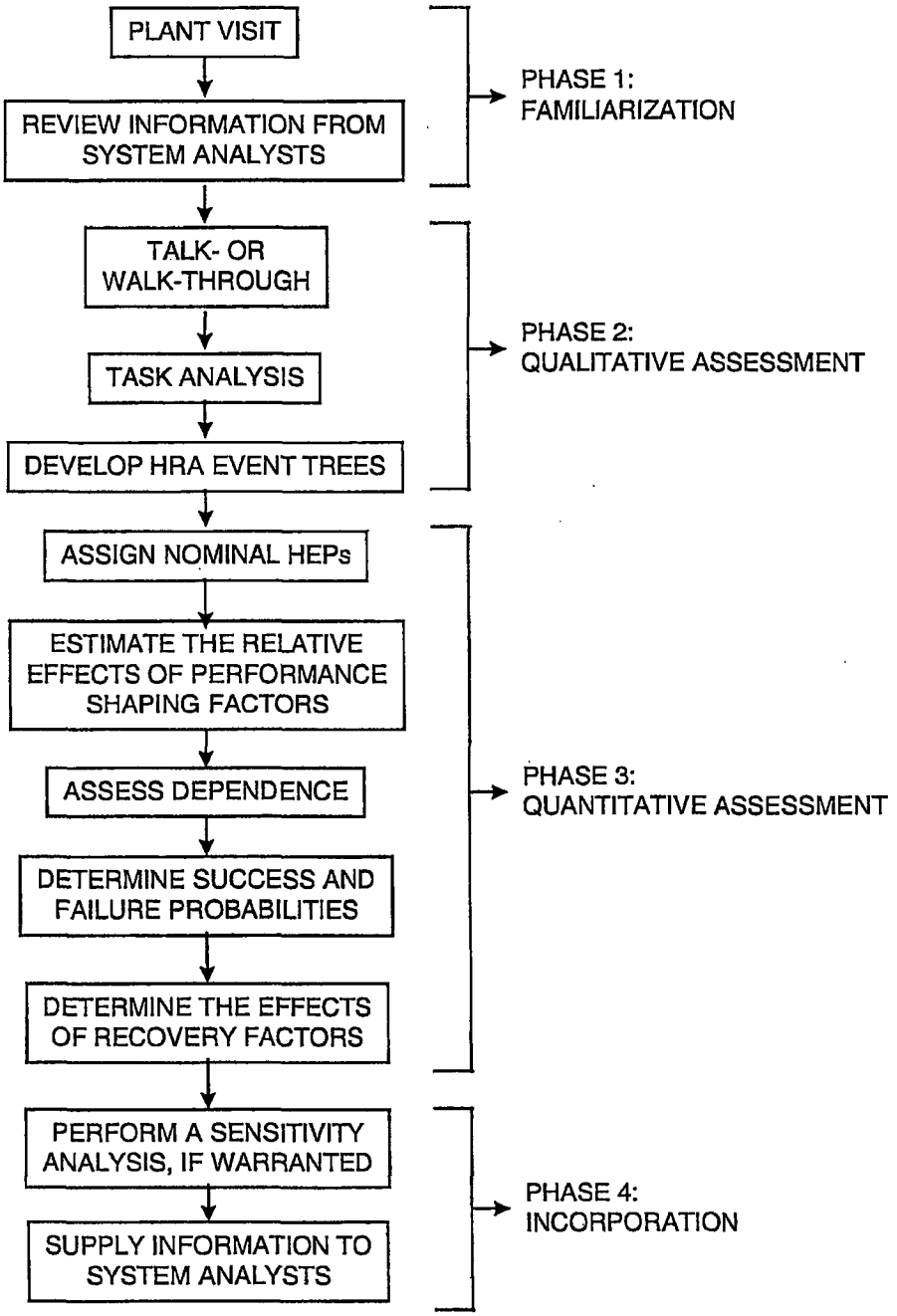


Figure 9.6-1

9.7 Please augment Table 10-10 page 10-50 of the Hope Creek PUSAR to include the following information:

a) The HEPs for the OLTP plant and the CPPU plant,

Response
PUSAR Table 10-10 has been augmented to include the Human Error Probabilities (HEPs) specific to the CLTP configuration and the CPPU configuration.

The pre-EPU model is representative of the CLTP (3339 MWt) configuration and not the OLTP (3293 MWt) configuration. Hope Creek previously implemented a 1.4% Measurement Uncertainty Recapture (MUR) power uprate to increase the power level from 3293 MWt (OLTP) to 3339 MWt (CLTP). Therefore, the HEPs in Table 10-10 are provided for the CLTP configuration.

b) The human reliability quantification method that was used (e.g., CBDTM or a combination of CBDTM and the ASEP time reliability correlation), and

Response
Table 10-10 has been augmented to include the human reliability quantification method used for each HEP.

c) The risk achievement worth (RAW) of the human action for the CPPU plant, as determined from the CDF calculation. (Note: The NRC staff will use this information, along with the previous reported Fussell-Vesely importance measures, to determine the appropriate amount of review to perform in accordance with NUREG/CR-1764, "Guidance for the Review of Changes to Human Actions.")

Response
Table 10-10 has been augmented to include the risk achievement worth (RAW) for each human action for the CPPU configuration, as determined from the CDF cutset calculation.

Additional text enhancements to Table 10-10 and the associated notes are provided in bold text.

In addition, changes to the original PUSAR information are identified for the following:

- For operator action SAC-XHE-FO-HEA5B, the text under the "Action Description" and "Comment" columns has been revised to correct inconsistencies. In addition, a reference to

Note (4) has been added under the "Basis of Importance" Column and the text under the "HEP Re-Calculation Necessary" column has been changed from "No" to "Yes".

- For operator action SAC-XHE-FO-HEA5A, the text under the "Action Description" and "Comment" columns has been enhanced to provide additional description. In addition, a reference to Note (4) has been added under the "Basis of Importance" Column.

- The references to notes in Table 10-10 have been reformatted for consistency.

- For Note (3) to Table 10-10, the text has been enhanced to provide additional clarity.

- Note (4) to Table 10-10 has been added to provide additional clarity.

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Method	Comment
			CLTP	CPPU		CLTP	CPPU			
NR-XTIE-EDG	Failure to Crosstie Diesel Generator to opposite bus	F-V = 0.399	4 hrs.	4 hrs.	No	1.0	1.0	1.0	Note (6)	This operator action is a place holder in the PRA, modeled in the Hope Creek PRA with an HEP of 1.0. This action is not proceduralized and the crew indicated they would not perform it. As such, the CPPU has no effect on the current modeling of this operator action.
ACP-XHE-RE-SW04H	Failure to Recover Severe Weather LOOP (4 Hours)	F-V = 0.228	4 hrs.	4 hrs.	No	0.472	0.472	1.25	Note (7)	This is an offsite power recovery term. The time frame is based on nominal modeling time phases for LOOP scenarios determined principally by battery depletion time. The recovery failure probability is based on statistical analysis of the duration of industry LOOP events and not directly on HEP calculations. The CPPU does not affect the appropriateness of this time frame nor the recovery failure probability.

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Method	Comment
			CLTP	CPPU		CLTP	CPPU			
NR-XTIE-CHARG	Failure to Crosstie Energized Bus to Battery Charger Breaker	F-V = 0.177	3 hrs.	3 hrs.	No	0.6	0.6	1.12	Note (6)	This action is to cross tie power to a battery charger before the battery discharges. The CPPU does not affect the battery discharge time.
ACP-XHE-RE-PC04H	Failure to Recover Plant Centered and Grid Related LOOP (4 Hours)	F-V = 0.154	4 hrs.	4 hrs.	No	0.154	0.154	2.40	Note (7)	This is an offsite power recovery term. The time frame is based on nominal modeling time phases for LOOP scenarios determined principally by battery depletion time. The recovery failure probability is based on statistical analysis of the duration of industry LOOP events and not directly on HEP calculations. The CPPU does not affect the appropriateness of this time frame nor the recovery failure probability.

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Method	Comment
			CLTP	CPPU		CLTP	CPPU			
SAC-XHE-FO-HEA5B	**Dependent combination of operator action SAC-XHE-FO-HEAT, failure of SACS heat load manipulation, and** Operator Action SWS-XHE-FO-2355B, Failure to Open SACS-SW Heat Exchanger Valve 2355B Locally	F-V = 0.116 **Note (4)**	46 min	40 min **Note (3)**	**Yes**	9.04E-3	1.04E-2	6.36 Note (4)	Note (8)	**This is a dependent HEP combination. The manipulation of SACS heat loads (operator action SAC-XHE-FO-HEAT) is evaluated in the PRA for the worst case conditions of high river water temperature and high SACS temperatures. For these conditions, the time frames for crew action result in a change in the calculated HEP. This action is required for certain SACS configurations that may occur following a LOOP event. The local opening of the 2355B valve is set to 1.0.**

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Method	Comment
			CLTP	CPPU		CLTP	CPPU			
NR-VENT-5-03	Failure to Initiate Containment Venting	F-V = 0.115	~ 20 hrs. **Note (1)**	20 hrs.	No	2.59E-3	2.59E-3	45.5	Note (6)	This operator action represents failure to align the containment vent. The time frame is 20 hours based on the time to reach the containment vent pressure. The CPPU does not affect the appropriateness of this extremely long time frame nor the failure probability determined based on this long time frame.
ADS-XHE-OK-INHIB	Automatic ADS Inhibited (Non-ATWS)-- Success Of The Action	F-V = 0.075	~14 min.	12 min.	No	1.0	1.0	1.0	Note (6)	This is not a human error. This action is to successfully inhibit automatic ADS actuation. An override success probability of 1.0 is used. CPPU implementation is not judged to affect his probability. Any decrease in the success probability associated with CPPU implementation would decrease the risk of CPPU implementation.

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Metho d	Comment
			CLTP	CPPU		CLTP	CPPU			
ACP-XHE-RE-SW20H	Failure to Recover Severe Weather LOOP (20 Hours)	F-V = 0.066	20 hrs.	20 hrs.	No	0.162	0.162	1.34	Note (7)	This is an offsite power recovery term. The time frame is based on nominal modeling time phases for LOOP scenarios determined principally by battery depletion time. The recovery failure probability is based on statistical analysis of the duration of industry LOOP events and not directly on HEP calculations. The CPPU does not affect the appropriateness of this time frame nor the recovery failure probability.
CAC-XHE-FO-NPSH	Failure to prevent steam binding of ECCS pump During Cont Vent	F-V = 0.064	80 min.	69 min. **Note (3)**	Yes	0.21	0.21	1.24	Note (6)	The operator action to vent the containment so that NPSH is not lost for pumps using the suppression pool. No change in the HEP using the Cause Based Decision Tree Method, EPRI TR 100259.[2] (Reference 34A]

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Method	Comment
			CLTP	CPPU		CLTP	CPPU			
NR-SPL-LVLL-4	Failure to Align Core Spray to the CST for Late Injection (Post Containment Challenge)	F-V = 0.064	> 24 hrs. **Note (1)**	> 24 hrs. **Note (1)**	No	0.204	0.204	1.25	Note (6)	This operator action represents failure to align the Core Spray to the CST for injection post containment failure. The time frame is > 24 hours based on the time to reach the ultimate containment failure pressure. The CPPU does not affect the appropriateness of this time frame nor the failure probability determined based on this long time frame.

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Method	Comment
			CLTP	CPPU		CLTP	CPPU			
SAC-XHE-FO-HEA5A	**Dependent combination of operator action SAC-XHE-FO-HEAT, failure of SACS heat load manipulation, and** Operator Action SWS-XHE-FO-2355A, Failure to Open SACS-SW Heat Exchanger Valve 2355A Locally	F-V = 0.056 **Note (4)**	46 min.	40 min. **Note (3)**	Yes	9.04E-3	1.04E-2	1.0 Note (4)	Note (8)	This is a dependent HEP combination. The manipulation of SACS heat loads **(operator action SAC-XHE-FO-HEAT)** is evaluated in the PRA for the worst case conditions of high river water temperature and high SACS temperatures. For these conditions, the time frames for crew action result in a change in the calculated HEP. This action is required for certain SACS configurations that may occur following a LOOP event. The local opening of the 2355A valve is set to 1.0.

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Method	Comment
			CLTP	CPPU		CLTP	CPPU			
UV1-XHE-FO-ALIGN	Failure to Align FP for Late RPV Injection	F-V = 0.053	~ 20 hrs. **Note (1)**	20 hrs.	No	0.99	0.99	1.0	Note (6)	This operator action is modeled in the Hope Creek PRA with an HEP of 0.99 due to procedural limitations. The SAGs direct use of FP for RPV injection, but FP injection is not referenced in the EOPs. As such, The CPPU has no effect on the current modeling of this operator action.

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Metho d	Comment
			CLTP	CPPU		CLTP	CPPU			
SWS-XHE-PROC	Failure to Align SSW for Late RPV Injection	F-V = 0.053	~ 20 hrs. **Note (1)**	20 hrs.	No	1.0	1.0	1.0	Note (9)	This operator action is modeled in the Hope Creek PRA with an HEP of 1.0 due to procedural limitations. The SAGs direct use of SSW for RPV injection, but SSW injection is not referenced in the EOPs. As such, The CPPU has no effect on the current modeling of this operator action.

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Method	Comment
			CLTP	CPPU		CLTP	CPPU			
NR-U1X-DEP-SRV	Failure to Depressurize with SRV w/o High Pressure. Injection.	F-V = 0.047	~33 min.	27 min.	Yes	2.6E-4	3.6E-4	131	Note (10)	The Hope Creek PRA uses a value of 27 minutes for the HEP calculations for depressurization based on MAAP Cases IB-LI-3-SBO (HC0010) and ID-LI-7B3 (HC0017). The MAAP cases indicate that the time allowable for the CPPU case is reduced approximately 6 minutes. This decrease in time is calculated to result in a change in the quantified HEP. This basic event change was included in the evaluation of the change in risk metrics (see Table 10-8) as one of the contributors to the risk increase.
NR-%IE-SWS	Non-recovery of %IE-SWS	F-V = 0.035	-	-	No	0.1	0.1	1.32	Note (11)	Not quantified - it is judged that the probabilities are not significantly different based on plant response and calculations using the Cause Based Decision Tree Method, EPRI TR 100259.[(2)] (Reference 34)

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Method	Comment
			CLTP	CPPU		CLTP	CPPU			
RX-FW-ADS	Dependent Operator Actions - Operator. Fails FW Control and ADS	F-V = 0.02	~4-30 min.	~4-27 min.	Yes	1.8E-5	2.4E-5	832	Note (8)	The constituent events of this combination HEP are NRQFWLVH4M-03 and NR-U1X-DEP-SRV. For event NRQFWLVH4M-03, the time frame for the operator action is estimated to be 4 minutes based on operator interviews. This time is based on the time available for operators to reduce FW flow before potentially reaching the Level 8 high level trip following a scram. The 4 min. time frame is expected to be dependent on the response of the FW control system and not significantly affected by CPPU. For event NR-U1X-DEP-SRV, the CPPU effect on the HEP has been calculated. (See NR-U1X-DEP-SRV in this table.) The dependent HEP combination failure probability is reassessed to determine the effect of CPPU. The basic event was modified and included in Table 10.8 as one of the contributors to the

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Metho d	Comment
			CLTP	CPPU		CLTP	CPPU			
										risk increase.
SAC-XHE-FO-HEAT	SACS Heat Load Manipulation	F-V = 0.019	46 min.	40 min. **Note (3)**	Yes	9.04E-3	1.04E-2	6.36 Note (5)	Note (10)	The manipulation of SACS heat loads is evaluated in the PRA for the worst case conditions of high river water temperature and high SACS temperatures. For these conditions, the time frames for crew action result in a change in the calculated HEP. This action is required for certain SACS configurations that may occur following a LOOP event.

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Metho d	Comment
			CLTP	CPPU		CLTP	CPPU			
RHS-REPAIR-TR	Repair/Recovery of RHR For Loss of DHR Events	F-V = 0.019	~ 20 hrs. **Note (1)**	20 hrs.	No	0.35	0.35	1.04	Note (12)	This is a recovery term for long term loss of DHR sequences. The time frame is 20 hours based on the time to pressurize the containment and close the SRVs. The recovery failure probability is based on a mean time to repair of 19 hours for pumps and not directly on HEP calculations. The CPPU does not affect the appropriateness of this time frame nor the recovery failure probability determined based on their long time frame.
IGS-XHE-FO-V5125	Failure to open cross connect valve	F-V = 0.011	~ 20 hrs.	~ 20 hrs.	No	0.118	0.118	1.09	Note (6)	This action supports the containment vent action. The timing required is in excess of 20 hours. No measurable difference in the calculated HEP is found for CPPU.

Table 10-10

DISPOSITION OF KEY ACTIONS FOR POTENTIAL HEP RE-CALCULATION

Basic Event ID	Action Description	Basis of Importance	Action Time Available		HEP Re-Calculation Necessary	HEP		RAW (CPPU CDF)	HEP Calc. Method	Comment
			CLTP	CPPU		CLTP	CPPU			
NR-RHR-INIT-L	Failure to initiate RHR (Late)	F-V = 0.010	~ 20 hrs. **Note (1)**	20 hrs.	No	2.1E-6	2.1E-6	4710	Note (6)	This is a system initiation action for long term loss of DHR sequences. The time frame is 20 hours based on the time to pressurize the containment and close the SRVs. The small relative change in the time available for diagnosis and action due to CPPU implementation does not affect the calculation of the HEP due to the extremely long time available from the initial cue. The CPPU does not affect the appropriateness of this time frame nor the recovery failure probability determined based on their long time frame.

Notes to Table 10-10:

(1) The action time available for the CLTP case is expected to be approximately the same or slightly more; however, a formal assessment of the time available for the CLTP case is not necessary in determining whether a change in the HEP calculation is warranted. The actions for which this note applies have HEPs that are conservative in nature and would not be affected by the potential changes in available timings due to the CPPU.

(2) The HEPs are, in general, calculated using the EPRI Cause-Based Methodology for the cognitive portion of the analysis (as implemented in the EPRI HRA Calculator). The EPRI calculator methodology results in minimal effects on the calculated HEPs due to CPPU implementation.

(3) CPPU action time is calculated based on a decay heat level 12.3% greater than OLTP**, which is based on PSEG calculation BC-0052(Q), Rev. 2, "Plant Cooldown Using One RHR Heat Exchanger." BC-0052(Q), Rev. 2 stated that:**

> ***"112.3% thermal power is assumed to be adequate, based on engineering judgment, to represent the decay heat after the EPU is finished."***

BC-0052(Q), Rev. 2 was the latest available decay heat calculation at the time to support the PUSAR HRA development for the identified operator actions. BC-0052(Q), Rev. 2 was evaluated using a decay heat level 112.3% of OLTP, or 3700 MWt. Calculation BC-0052(Q) has been updated to Rev. 3 to specifically address the CPPU configuration. BC-0052(Q), Rev. 3 is evaluated using a decay heat level 102% of CPPU, or 3917 MWt. However, BC-0052(Q), Rev. 3 was not available at the time for the deterministic calculations used to support the HRA development for the PUSAR.

The HEPs used in the PUSAR analysis resulted in conservative calculations of the change in risk metric due to overestimation of the change in HEP values. A conservatism removed from the HEP calculation involved the time to the cue for the operator action timing. The time to the cue has been decreased for the CPPU configuration compared to the pre-EPU configuration due to the higher decay heat level. Therefore, as a result of the changes from CLTP to CPPU, the newly derived HEPs, the HEP changes, and the risk changes used in the PUSAR are now considered best estimates and accurately reflect the change in power levels, i.e., much of the conservatism has been eliminated from the calculations.

(4) The RAW for dependent operator action SAC-XHE-FO-HEA5B (RAW = 6.36) is higher than the RAW for dependent operator action SAC-XHE-FO-HEA5A (RAW = 1.0) because valve 2355B is modeled as normally closed during power operation while valve 2355A is modeled as normally open.

Similarly, the Fussell-Vesely (F-V) for dependent operator action SAC-XHE-FO-HEA5B (F-V = 0.116) is higher than the F-V for dependent operator action SAC-XHE-FO-HEA5A (F-V = 0.056) because valve 2355B is modeled as normally closed during power operation while valve 2355A is modeled as normally open

(5) The RAW for dependent operator action SAC-XHE-FO-HEA5B is judged to be the same as the RAW for the independent operator action for SACS heat load manipulation (SAC-XHE-FO-HEAT) because the HEP for local manipulation of the SW HX MOVs is 1.0.

Notes to Table 10-10 (cont'd):

(6) The HEP calculation is based on using the CBDTM for the cognitive portion of the HEP and THERP for the execution portion of the HEP as implemented in the EPRI HRA calculator.

(7) The value is based on an evaluation of industry LOOP non-recovery data (e.g., *Losses of Off-Site Power at U.S. Nuclear Power Plants Through 2001,* EPRI TR-1002987, April 2002) and is not based on an HEP calculation.

(8) The calculation of the joint HEP for the dependent operator action combinations is based on the methodology provided in NUREG/CR-1278.

(9) This operator action is not proceduralized in the Hope Creek EOPs. Therefore, it is conservatively not credited in the Hope Creek PRA. The HEP is 1.0 and is not based on an explicit HRA calculation.

(10) The HEP calculation is based on using a combination of the CBDTM and the ASEP time reliability correlation for determining the cognitive portion of the HEP. The time dependent non-response (i.e., cognitive) probabilities from the ASEP methodology are applied for short term actions (e.g., time available for diagnosis <1 hour) in order to compensate for possible non-conservative estimates produced by the CBDTM methodology. The total non-response probability for short term action is taken to be the sum of the cause-based and ASEP results.

(11) The recovery value is not explicitly quantified using HRA methods and is based on a screening value. Loss of SSW initiators are judged to be slow developing events such that several hours are available to perform recovery actions.

(12) The recovery value is not explicitly quantified using HRA methods and is based on a mean time to repair model.

9.8 In the Hope Creek PUSAR, Sections 10.5.5.1 and 10.5.5.2, Pages 10-23 through 10-25: The NRC staff understands that the seismic PRA and the Fire Induced Vulnerability Evaluation (FIVE), which were performed as part of the Individual Plant Examination - External Events (IPEEE), have not been updated to reflect the Revision 2005B PRA model. Confirm that the changes made to the PRA's logic model since the IPEEE was submitted do not significantly affect the IPEEE conclusions concerning seismic and internal fire risk.

Response

Hope Creek performed an evaluation of external risk hazards in the Individual Plant Examination of External Events (IPEEE) (Reference 9.8-1).

Included in this response are the following:

a) A summary of the major changes incorporated into the Full Power Internal Events (FPIE) PRA model since the IPEEE was submitted in 1997.

b) Excerpts from the Hope Creek IPEEE results for seismic and internal fire risk. These excerpts indicate the characteristics of the risk profile contributors from the IPEEE.

c) Potential effect on the IPEEE conclusions concerning seismic and internal fire risk is also provided due to the major changes in the FPIE model.

Major changes made to the PRA model since the IPEEE was submitted are judged not to affect the IPEEE conclusions concerning seismic and internal fire risk for the EPU evaluation.

Major Changes to the FPIE PRA Model Since the IPEEE

Major changes to the FPIE PRA model since the IPEEE include the following:

- Updates of initiating event frequencies using latest plant specific and industry data sources
- Complete update of the event tree sequence modeling (including transient, LOCA, ATWS and LOOP sequences)
- Complete update of the internal flooding analysis
- Incorporation of realistic success criteria using plant specific thermal hydraulic analysis
- Complete update of the Human Reliability Analysis, including review of procedures, interviews with operating crews, and incorporation of realistic times available for operator actions based

on using plant specific thermal hydraulic analysis. In addition, incorporate dependent HEP evaluation.

- Update system fault tree logic to reflect new hardware, procedures, and plant engineering calculations
- Update of system unavailability and system unreliability data using latest plant specific and industry data sources
- Update Common Cause Failure (CCF) data based on latest industry data
- Incorporate comments from BWROG PRA Peer Review
- Incorporate "gaps" from PRA self assessment against ASME PRA Standard (ASME RA-S-2002).
- Conversion of the PRA model from the NUPRA software environment to the CAFTA software environment

Seismic Risk Results from IPEEE

The total CDF from seismic events at HCGS was calculated to be 3.6E-6/yr if the Livermore (LLNL) seismic hazard curve is used and 1.0E-6/yr if the EPRI hazard curve is employed. [9.8-1] The most important seismic sequences are shown in Table 9.8-1 (LLNL values reported).

The five seismic sequences in Table 9.8-1 represent 95% of the total core damage frequency for seismic events, with SDS-36 (S-IC1) being the largest single contributor at 69.4% of the total seismic CDF. Based on these results, none of the seismic sequences investigated represent new or unique significant plant vulnerabilities.

No relay chatter interactions requiring human actions are needed based on the "low ruggedness" relay evaluation. It is concluded that relay chatter is not significant to safe shutdown after a seismic event at the Hope Creek plant.

Containment performance systems and equipment were explicitly included in the walkdowns and seismic PRA. No vulnerabilities which could cause early failures of containment, or containment bypass were identified.

The principal conclusion is that the seismic evaluations did not identify any unique or new vulnerabilities for the Hope Creek plant.

Impact of PRA Changes on Seismic IPEEE Dominant Sequences

The top five seismic sequences represent approximately 95% of the seismic IPEEE CDF. The following discussion evaluates the impact of the PRA model changes on the seismic IPEEE dominant sequences which are listed in Table 9.8-1. Changes in the dominant seismic contributors as a result of the change in

power level from the pre-EPU to the EPU configuration are discussed in the following:

- Sequence SDS 36 (S-IC1) – This sequence is a seismic induced failure of all four divisions of 1E 120V AC instrumentation distribution panels 1A/B/C/DJ481. This sequence contributes to 69.4% of the base seismic IPEEE CDF. Sequence SDS 36 is assumed to lead directly to core damage due to seismic induced loss of RPV injection and containment heat removal support systems. The 1A/B/C/DJ481 panels distribute instrumentation power to diesel generator control panels; various SACS, RHR, Core Spray, HPCI and RCIC valves and/or control panels; class 1E 4160V AC switchgear; class 1E 125V DC and 1E 250V DC battery chargers and switchgear; Remote Shutdown Panel instrumentation; and various other 1E loads.

  Innovative operator actions to allow manual control of the plant are not credited for the seismic IPEEE. The Conditional Core Damage Probability (CCDP), given the seismic failures, is 1.0. This is independent of the EPU or pre-EPU power level.

  The Hope Creek Full Power Internal Events (FPIE) PRA does not credit manual control of mitigation equipment without 1E 120V AC instrumentation distribution panels 1A/B/C/DJ481. Changes to the Hope Creek PRA model since the IPEEE have no impact on this seismic IPEEE sequence.

- Sequence SDS 37 (S-DC) – This sequence is a seismic induced failure of 1E power to all four 125V DC distribution panels 1A/B/C/D-D-417. This sequence contributes to 12.2% of the base seismic IPEEE CDF. Sequence SDS 37 is assumed to lead directly to core damage due to seismic induced loss of RPV injection and containment heat removal support systems.

  A failure of power to DC Panels 1A/B/C/D-D-417 would mean a loss of DC control power to the safety-related systems. Manual control would be difficult to credit without 125V DC power, and core damage results. The CCDP, given the seismic failures, is 1.0. This is independent of the EPU or pre-EPU power level.

- SDS-26 (S-OP-HP) – This sequence is a seismic-induced loss of offsite power and failure of 1E 250V DC (high pressure injection), with simultaneous random failures which result in core damage. This sequence contributes to 5.3% of the base seismic IPEEE CDF. The frequency of a seismic induced failure of offsite power is

dominated by the failure of the ceramic insulator columns in either the switchyard or the incoming transformers. The random failures which cause core damage are dominated by reactor depressurization failures which result in inadequate ECCS injection or Emergency Diesel Generator (EDG) failures which result in station blackout.

The PRA success criteria for manual RPV depressurization has been revised from requiring 1 of 14 SRVs (pre-EPU) to 2 of 14 SRVs (post-EPU) as described in PUSAR Section 10.5.4.2. Due to the large number of redundant SRVs to perform the manual RPV depressurization function, the change in success criteria has a negligible impact on the seismic risk evaluation for the EPU configuration. In addition, enhancements to the Human Reliability Analysis (HRA) have not significantly altered the operator failure probability for manual RPV depressurization.

There have been no significant PRA changes to the EDG system operation or configuration. The Hope Creek FPIE PRA has incorporated the latest available generic and plant specific EDG unreliability and unavailability data. Based on industry trends, the EDG unreliability and unavailable probabilities have decreased due to improvements in maintenance practices. In addition, recent industry studies (e.g., NUREG/CR-5495, Common-Cause Failure Parameter Estimations) have shown a decrease in the EDG common cause failure (CCF) parameters.

The decrease in both the EDG random and CCF probabilities would likely reduce the CDF for this seismic scenario. However, changes to the SACS success criteria to support EDG cooling could potentially increase the CDF for this seismic scenario. Despite the changes to the Hope Creek FPIE PRA impacting EDG failure probabilities, the insights from this seismic sequence (e.g., seismic induced failure of offsite power is dominated by the failure of the ceramic insulator columns) is unaffected. [9.8-1]

No other changes to the Hope Creek PRA model since the IPEEE are judged to have an impact on this seismic IPEEE sequence. The CCDP is expected to be similar for both the EPU and pre-EPU conditions, i.e., to increase or decrease based on plant and model changes by the same for both cases.

- SDS-35 (S-IC2) – This sequence is a seismic induced failure of all four divisions of 1E 120V AC instrumentation distribution panels 1A/B/C/DJ482. (Note that seismic sequence SDS-36 separately

models failure of 1E 120V AC instrumentation distribution panels 1A/B/C/DJ481.) This sequence contributes to 4.4% of the base seismic IPEEE CDF. Credit is taken for manual system control to prevent core damage, but failure of both automatic actions (due to seismic induced failures) and manual actions results in core damage and primary containment isolation failure.

Given failure of all four of these panels, operator action can still prevent core damage. [9.8-1] The 1A/B/C/DJ482 panels distribute 1E 120V AC power to various 1E logic cabinets. The failure of these logic cabinets causes a substantial loss of automatic actuation of 1E equipment, including diesel generator load sequencing and automatic Primary Containment Isolation System signals. However, manual operation of this equipment and manual diesel generator loading is still possible (e.g., at the Remote Shutdown Panel), and procedural guidance is available. The remote shutdown operator action described in Section 3.1.5.3.2 of the Hope Creek IPEEE [9.8-1] is conservatively used to represent this recovery action. This is conservative since manual actions can be performed directly from the control room.

The Hope Creek FPIE PRA does not credit manual operator actions from the remote shutdown panel. However, the FPIE does credit operator action to manually start and load an EDG given failure to automatically start. Crediting this operator action could potentially reduce the CDF for this seismic scenario, but the Hope Creek IPEEE has previously identified this as a conservatism in the IPEEE model. [9.8-1]

No other changes to the Hope Creek PRA model since the IPEEE are judged to have an impact on this seismic IPEEE sequence. The CCDP is expected to be similar for both the EPU and pre-EPU conditions, i.e., to increase or decrease based on plant and model changes by the same for both cases.

- SDS-18 (S-OP) – This sequence is a seismic-induced loss of offsite power with subsequent random failures which result in core damage. This sequence contributes to 3.6% of the base seismic IPEEE CDF. The frequency of a seismic induced failure of offsite power is dominated by the failure of the ceramic insulator columns in either the switchyard or the incoming transformers. The random failures are dominated by failure of the Emergency Diesel Generators (EDGs) and their support systems, which result in station blackout.

There have been no significant PRA changes to the EDG system operation or configuration. The Hope Creek FPIE PRA has incorporated the latest available generic and plant specific EDG unreliability and unavailability data. Based on industry trends, the EDG unreliability and unavailable probabilities have decreased due to improvements in maintenance practices. In addition, recent industry studies (e.g., NUREG/CR-5495, Common-Cause Failure Parameter Estimations) have shown a decrease in the EDG common cause failure (CCF) parameters.

The decrease in both the EDG random and CCF probabilities would likely reduce the CDF for this seismic scenario. However, changes to the SACS success criteria to support EDG cooling could potentially increase the CDF for this seismic scenario. Despite the changes to the Hope Creek FPIE PRA impacting EDG failure probabilities, the insights from this seismic sequence (e.g., seismic induced failure of offsite power is dominated by the failure of the ceramic insulator columns) is unaffected. [9.8-1]

No other changes to the Hope Creek PRA model since the IPEEE are judged to have an impact on this seismic IPEEE sequence. The CCDP is expected to be similar for both the EPU and pre-EPU conditions, i.e., to increase or decrease based on plant and model changes by the same for both cases.

Fire Risk Results from IPEEE

A total CDF from fire events at HCGS was calculated to be 8.1E-05 per year. [9.8-1] This CDF should be viewed as an upper bound because of the extremely conservative assumptions in the fire damage modeling. The most important buildings are described in Table 9.8-2. Based on the fire risk results from the IPEEE (see Table 9.8-2), the fire CDF is dominated by fires in the Control/Diesel building. The Control/Diesel Building, which houses the control area and the diesel generators, is the most significant building contributing 86% of the fire induced CDF. This was expected because of the good separation of equipment in the Reactor Building and the lack of safety related equipment in the other buildings. Typically, the fire risk is dominated by rooms or areas in which there is a confluence of equipment and/or cables from different electrical divisions. This occurs in the Control/Diesel Building at HCGS, particularly in the cable spreading room, lower control equipment room, control equipment room mezzanine, upper control equipment room, diesel generator rooms, electrical access rooms, and control room (see Table 9.8-3).

More than 200 fire compartments were analyzed in the IPEEE Fire Study. Thirty-eight fire compartments did not screen out in the Fire IPEEE study using the FIVE

criteria (CDF <1E-6/yr). Table 9.8-3 shows the top 16 compartment contributors to the Fire CDF. These 16 compartments represent more than 95% of the total Fire IPEEE CDF.

The HCGS IPEEE identified that the Fire Risk Scoping Study (NRC, 1989b) Safety issues were addressed during the IPEEE fire analysis and it was found that each of the issues has been adequately addressed at HCGS.

Impact of PRA Changes on Fire IPEEE Dominant Compartments

The top five fire compartments represent approximately 64% of the fire IPEEE CDF. The following discussion evaluates the impact of the PRA model changes on these top five fire IPEEE dominant compartments which are listed in Table 9.8-3. Changes in the dominant fire contributors as a result of the change in power level from the pre-EPU to the EPU configuration are discussed in the following:

- Control Room – The Hope Creek control room fire scenarios, similar to most plants, are dominated by large, unsuppressed fire scenarios that include abandonment of the control room and subsequently regaining of control from the remote shutdown panel. [9.8-1] This compartment contributes to 30.86% of the base fire IPEEE CDF. Control rooms are typically one of the top five risk significant compartments. The HCGS calculated value of 2.5E-05/yr. is typical of values found for other plants. The CCDP is dominated by operator failure to control the plant from the remote shutdown panel. This CCDP remains the same regardless of the EPU or pre-EPU power level because it is dominated by access and stress related performance shape factors.

  The Hope Creek FPIE PRA does not credit manual operator actions from the remote shutdown panel. No other changes to the Hope Creek PRA model since the IPEEE are judged to have an impact on the risk contribution of this fire IPEEE compartment.

- Class 1E (Ch. A) Switchgear Room – The Channel A switchgear room is important because it provides electrical power to Channel A safety related equipment. This compartment contributes to 16.05% of the base fire IPEEE CDF. This analysis assumed, as is typically performed, that any cabinet fire in this room can cause loss of a channel. Relaxation of this assumption would require detailed knowledge of cable end points in these rooms. These rooms do not have automatic fire suppression systems.

The CCDP is dominated by random failure of the Channel B equipment. The PRA model changes do not change the IPEEE conclusions or insights for this compartment. No change in CCDP is expected for the change from the pre-EPU to the EPU configuration.

- Diesel Generator (Ch. A) Room – A fire in a diesel generator room is typically not a risk significant fire compartment. For the Hope Creek Fire IPEEE, the diesel generator rooms emerge as important fire risk locations because of an unusual configuration in which both sets of Class 1E 4kV offsite power bus bars run along the ceiling of these rooms. The Diesel Generator (Ch. A) Room compartment contributes to 6.54% of the base fire IPEEE CDF. The following assessment is similar for the other three diesel generator rooms.

  A loss of offsite 4kV power was assumed for fires large enough to be calculated as causing a short circuit of the bus bars. Because both sets of bus bars run in relatively close proximity to each other, at the diesel exhaust manifold end of the room, the loss of both bus bars was assumed to occur simultaneously. A large fire was also assumed to disable the diesel generator which initiated the fire. The CCDP is dominated by common cause failure of the remaining three diesel generators.

  For the Diesel Generator A Room fire, HPCI and/or RCIC are initially available for a majority of the core damage scenarios. Core damage is delayed for several hours; therefore, the impact of EPU on operator action timing is limited. The change in CDF or CCDP for the Diesel Generator A Room is expected to be negligible when calculating the change due to EPU implementation.

  The Hope Creek FPIE PRA has incorporated the latest available generic and plant specific EDG unreliability and unavailability data. Based on industry trends, the EDG unreliability and unavailable probabilities have decreased due to improvements in maintenance practices. In addition, recent industry studies (e.g., NUREG/CR-5495, Common-Cause Failure Parameter Estimations) have shown a decrease in the EDG common cause failure (CCF) parameters.

- CRD Pump Area – The CRD pump area contains Division II cables passing over cabinets. The fire damage calculations indicate that cables passing directly over cabinets may be damaged by fully developed cabinet fires. Therefore, Division II cables were calculated as failing with the frequency of cabinet fires in this compartment. This room does not contain automatic suppression.

A complete failure of Division II was assumed. Relaxation of this assumption would require detailed knowledge of the cable end points passing within and through this room.

The CRD Pump Area contributes to 5.19% of the base fire IPEEE CDF. The change in CDF or CCDP for the CRD Pump Area is expected to be negligible when calculating the change due to EPU implementation because the risk contribution is due to hardware failures. The PRA model changes do not change the IPEEE conclusions or insights for this compartment.

- Diesel Generator (Ch. B) Room – The Diesel Generator (Ch. B) Room compartment contributes to 5.06% of the base fire IPEEE CDF. The change in CDF or CCDP for the Diesel Generator B Room is expected to be negligible when calculating the change due to EPU implementation. See similar discussion for the Diesel Generator (Ch. A) Room.

Summary of Impact of PRA Changes on IPEEE Conclusions

Major changes made to the PRA model since the IPEEE was submitted are judged not to affect the IPEEE conclusions concerning seismic and internal fire risk for the EPU evaluation.

Seismic Risk

Based on the seismic risk results from the IPEEE, the seismic CDF is dominated by seismic induced failure of plant 120V AC and 125V DC support systems. Seismic induced failure of certain 120V AC and 125V DC support systems leads directly to core damage. Changes to the PRA model would have no impact on the dominant seismic sequences (e.g., the major HCGS PRA model changes did not impact anchorage assumptions). Therefore, changes to the PRA model are judged to have a minor or negligible impact on the seismic CDF.

Section 1.4.1 of the IPEEE states:

> *"...the seismic evaluations did not identify any unique or new vulnerabilities for the Hope Creek plant."*

The changes made to the PRA model are judged not to alter the conclusion of the IPEEE seismic risk evaluation.

Fire Risk

Based on the fire risk results from the IPEEE (see Table 9.8-2), the fire CDF is dominated by fires in the Control/Diesel building. The Control/Diesel Building, which houses the control area and the diesel generators, is the most significant building contributing 86% of the fire induced CDF. This was expected because of the good separation of equipment in the Reactor Building and the lack of safety related equipment in the other buildings. Typically, the fire risk is dominated by rooms or areas in which there is a confluence of equipment and/or cables from different electrical divisions. This occurs in the Control/Diesel Building at HCGS, particularly in the cable spreading room, lower control equipment room, control equipment room mezzanine, upper control equipment room, diesel generator rooms, electrical access rooms, and control room (see Table 9.8-3).

The changes made to the PRA model would have no impact on the dominant fire sequences (e.g., the major HCGS PRA model changes did not impact the location of equipment or the routing of cables). The fire CDF is significantly influenced by several factors including the fire ignition frequencies, the location of mitigation equipment, the location of cable routing, and the available fire barriers. Therefore, changes to the PRA model are judged to have a minor or negligible impact on the fire CDF.

Section 4.6.7.1 of the IPEEE states:

> *"...there are no areas of the plant for which corrective actions should be taken with respect to reduction in the likelihood or severity of fire induced core damage scenarios."*

Changes to the PRA model are judged not to alter the conclusion of the IPEEE fire risk evaluation.

Reference

9.8-1 Hope Creek Generating Station, Individual Plant Examination of External Events (IPEEE), Public Service Electric and Gas Company, July 1997.

Table 9.8-1
HOPE CREEK SEISMIC IPEEE CDF (LLNL VALUES)

Sequence	Description	CDF (/yr)	Percent of Total CDF
SDS 36 (S-IC1)	A seismic induced failure of all four divisions of 1E 120V AC instrumentation distribution panels 1A/B/C/DJ481. This sequence is assumed to lead directly to core damage.	2.5E-6	69.4
SDS 37 (S-DC)	A seismic induced failure of 1E power to all four 125V DC distribution panels 1A/B/C/D417. This sequence is assumed to lead directly to core damage.	4.4E-7	12.2
SDS-26 (S-OP-HP)	A seismic-induced loss of offsite power and failure of high pressure injection, with simultaneous random failures which result in core damage. The random failures which cause core damage are dominated by reactor depressurization failures which result in inadequate ECCS injection or Emergency Diesel Generator (EDG) failures which result in station blackout.	1.9E-7	5.3
SDS-35 (S-IC2)	A seismic induced failure of all four divisions of 1E 120V AC instrumentation distribution panels 1A/B/C/DJ482. Credit is taken for manual system control to prevent core damage, but failure of both automatic and manual actions results in core damage and primary containment isolation failure.	1.6E-7	4.4
SDS-18 (S-OP)	A seismic-induced loss of offsite power with subsequent random failures which result in core damage. The random failures are dominated by Emergency Diesel Generator failures which result in station blackout.	1.3E-7	3.6

Table 9.8-2

HOPE CREEK FIRE IPEEE CDF BY BUILDING
(Reproduced from Table 4.28 of Hope Creek IPEEE [9.8-1])

Building	CDF (/yr)
Control/Diesel	7.0E-05
Reactor	8.0E-06
Turbine	2.0E-06
Radwaste	7.3E-07
Switchyard	3.0E-07

Table 9.8-3

HOPE CREEK FIRE IPEEE CDF BY FIRE COMPARTMENT
(Reproduced from Table 1-2 of Hope Creek IPEEE [9.8-1])

Building/ Elevation	Room	Description	Initiating Event	CDF/Year	Percent of Total
Aux – 137'	5510, 5511	Control Room	MSIV Closure LOOP SORV Loss of HVAC Loss of SWS Loss of SACS	2.5E-05	30.86
Aux – 130'	5416, 5417	Class 1E (Ch. A) Switchgear Room	MSIV Closure	1.3E-05	16.05
Aux – 102'	5307	Diesel Generator (Ch. A)	LOOP MSIV Closure	5.3E-06	6.54
RB – 77	4202	CRD Pump Area	MSIV Closure	4.2E-06	5.19
Aux – 102'	5306	Diesel Generator (Ch. B)	LOOP MSIV Closure	4.1E-06	5.06
Aux – 102'	5305	Diesel Generator (Ch. C)	LOOP MSIV Closure	3.7E-06	4.57
Aux – 130'	5412, 5413	Class 1E (Ch. B) Switchgear Room	MSIV Closure	3.0E-06	3.70
Aux – 137'	5501	Electrical Access	MSIV Closure	3.0E-06	3.70
Aux – 102'	5339	Electrical Access	LOOP MSIV Closure	2.7E-06	3.33
Aux – 163.6'	5605, 5631	Upper Control Eqpt. Computer Rooms	MSIV Closure	2.7E-06	3.33
Aux – 102'	5304	Diesel Generator (Ch. D)	LOOP MSIV Closure	2.6E-06	3.21
Aux – 124'	5401, 3425	Electrical Access	MSIV Closure	2.0E-06	2.47
RB – 102'	4301, 4309, 4310, 4311	North Side and Div. 1 SACS Area	MSIV Closure	1.8E-06	2.22
Aux – 102'	5302	Lower Control Electrical Eqpt. Room	LOOP SORV MSIV Closure	1.7E-06	2.10
TB – 102'	1315, 1316, 1317, 1320, 1321, 1322	Access and Unloading Area	LOOP	1.2E-06	1.48
RB – 102'	4303	MCC Area	MSIV Closure	1.2E-06	1.48
Total of Top Sixteen Compartments				7.72E-05	95.29

9.9 In the Hope Creek PUSAR, Section 10.5.7.2, Pages 10-31 and 10-32, and Figure 10-2: It is stated that a self-assessment of PRA quality was performed against the American Society of Mechanical Engineers (ASME) PRA standard. Please provide documentation of the self-assessment. Which addendum to the original ASME PRA standard was considered during the self-assessment? Were the NRC staff's clarifications and qualifications to the ASME PRA standard, which are provided in Appendix A of Regulatory Guide (RG) 1.200, incorporated into the PRA quality self-assessment process? Note: The NRC staff understands that the request for EPU is not risk-informed, that Revision 0 of RG 1.200 was in effect when the request for EPU was made, and that Revision 0 to RG 1.200 was only issued for trial use. The intent of the above questions is to help determine whether or not the PRA has sufficient technical adequacy to support the EPU application, specifically whether or not an onsite audit of the PRA is warranted.

Response

One of the key elements in the use of PRA input for integrated decision making is the quality of the PRA. The Hope Creek PRA was updated explicitly to provide a technically adequate tool for use in the EPU risk evaluation. The processes incorporated in the program plan included:

- Resolution of the Facts and Observations developed by the PRA Peer Review team (using NEI 00-02)
- Performance of a self assessment using the ASME PRA Standard

The PRA Peer Review Facts and Observations have been resolved in the PRA update.

A second method of characterizing the quality of the PRA is to meet the ASME PRA Standard as endorsed by the NRC in RG 1.200. Hope Creek performed a review of the ASME PRA Standard in conjunction with the PRA update in 2003 for its use in support of the EPU application and subsequently confirmed its applicability using ASME PRA Standard Addenda B and RG 1.200 issued for trial use.

Documentation of Self-Assessment

Table 9.9-1 summarizes the SRs that do not meet Capability Category II for the updated PRA self-assessment which applies to the PRA model used for the EPU assessment. Table 9.9-1 provides a disposition of the "gaps" for their potential impact on the EPU risk evaluation. Based on a review of Table 9.9-1 and the disposition of the "gaps", the HCGS PRA is judged to have sufficient technical adequacy to support the implementation of EPU for Hope Creek.

Standards Used for Self-Assessment

The HCGS PRA self-assessment identified in the PUSAR, Section 10.5.7.2, was performed in July 2003 using the original ASME PRA Standard (ASME RA-S-

2002). The July 2003 HCGS PRA self-assessment demonstrated that the HCGS PRA was suitable to support PRA applications that require ASME PRA Capability Category II, specifically to support EPU.

Subsequently, the ASME RA-Sb-2005 Addenda of the ASME PRA Standard (Addenda B) was issued. The HCGS PRA self-assessment was updated in June 2006 using this Addenda B of the ASME PRA Standard (ASME-RA-Sb-2005) and the RG 1.200 version that was available at the time for "trial use". The results of this updated HCGS PRA self-assessment identified those ASME PRA Standard Supporting Requirements (SRs) that are judged to not completely meet Capability Category II. As mentioned above, these items are identified in Table 9.9-1.

The original self assessment performed in July 2003 with the original ASME PRA Standard was performed without reference to the Regulatory Guide 1.200.

The subsequent self-assessment in June 2006 was performed to verify the condition of the HCGS PRA used in the EPU submittal and to incorporate the latest ASME PRA Standard Supporting Requirements (Addenda B) and the available RG 1.200 available at that time. This was performed as part of the June 2006 self-assessment.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
IE-A6	INTERVIEW plant personnel (e.g., operations, maintenance, engineering, safety analysis) to determine if potential initiating events have been overlooked.	Interview plant maintenance and engineering personnel for the purpose of identifying potential IEs that may have been overlooked.	The Hope Creek Initiating Events Notebook (HC PSA-001) includes a detailed evaluation of initiating events from industry studies. Special initiators are evaluated and dispositioned for inclusion in the Hope Creek PRA model based upon the unique HCGS plant and site features. Interviews with the operators and trainers revealed no additional initiating events. PSEG Engineering reviewed the initiating events analysis. Therefore, the task of interviewing plant personnel is not judged to have an impact on the EPU evaluation.
IE-C1a	When using plant-specific data, USE the most recent applicable data to quantify the initiating event frequencies. JUSTIFY excluded data that is not considered to be either recent or applicable (e.g., provide evidence via design or operational change that the data are no longer applicable.)	Update IE frequencies based on more recent data.	The IE frequency data was derived for the 2003 PRA update. Therefore, the use of the initiating event data for the 2003 PRA update may be considered not to be the "most recent" applicable data when examining the 2006 risk profile. As part of the 2007 PRA update, initiating events have been compiled for analysis. They indicated that the new IE data does not alter the conclusions of the EPU evaluation.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
IE-D3	DOCUMENT the key assumptions and key sources of uncertainty associated with the initiating event analysis.	Include a specific list of key assumptions.	The EPRI report on determining key assumptions and key uncertainties, which was published after the 2003 PRA update, has been reviewed and used for other BWR PRAs. It has been found to be useful in the identification of desirable sensitivity cases and for providing input to decision makers. This task has not been performed for HCGS. Documenting key assumptions is identified as a Supporting Requirement in the ASME PRA Standard (Addendum B) for meeting Capability Category II. This is judged to be primarily a documentation issue and judged to have no impact on EPU evaluation.
AS-C3	DOCUMENT the key assumptions and key sources of uncertainty associated with the accident sequence analysis.	Include a specific list of key assumptions.	The EPRI report on determining key assumptions and key uncertainties, which was published after the 2003 PRA update, has been reviewed and used for other BWR PRAs. It has been found to be useful in the identification of desirable sensitivity cases and for providing input to decision makers. This task has not been performed for HCGS. Documenting key assumptions is identified as a Supporting Requirement in the ASME PRA Standard (Addendum B) for meeting Capability Category II. This is judged to be primarily a documentation issue and judged to have no impact on EPU evaluation.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
SC-C3	DOCUMENT the key assumptions and key sources of uncertainty associated with the development of success criteria.	Include a specific list of key assumptions.	The EPRI report on determining key assumptions and key uncertainties, which was published after the 2003 PRA update, has been reviewed and used for other BWR PRAs. It has been found to be useful in the identification of desirable sensitivity cases and for providing input to decision makers. This task has not been performed for HCGS. Documenting key assumptions is identified as a Supporting Requirement in the ASME PRA Standard (Addendum B) for meeting Capability Category II. This is judged to be primarily a documentation issue and judged to have no impact on EPU evaluation.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
SY-A4	PERFORM plant walkdowns and interviews with system engineers and plant operators to confirm that the systems analysis correctly reflects the as-built, as-operated plant.	Document System Engineer interviews.	The plant walkdowns from the IPE were relied upon to establish the baseline PRA model. These walkdowns are not documented. The internal flood analysis had its own walkdown to confirm the flood sources, propagation paths, and targets. This flood walkdown is documented and judged to satisfy many of the items anticipated for the general walkdown. The interviews with system engineers were not performed, rather PSEG engineering reviewed the system notebooks and provided input for incorporation into the models and documents. The plant operators were interviewed regarding the restrictions, uses, and limitations of systems. The approaches taken for the PRA model are judged to be more than sufficient to support Capability Category II applications.
SY-A5	INCLUDE the effects of both normal and alternate system alignments, to the extent needed for CDF and LERF determination.	Consider and document alternate system alignments in PRA model (e.g., RHR in operation).	Judged to have no impact on EPU evaluation.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
SY-B6	PERFORM engineering analyses to determine the need for support systems that are plant-specific and reflect the variability in the conditions present during the postulated accidents for which the system is required to function.	Enhance analysis for the need for key support systems (e.g., room cooling).	Current evaluations of support system requirements may be slightly conservative. Support systems such as HVAC are assumed required based on PRA HVAC calculations from the IPE. Judged to have minimal impact on EPU evaluation.
SY-B7	BASE support system modeling on realistic success criteria and timing, unless a conservative approach can be justified, i.e. if their use does not impact risk significant contributors.	Enhance analysis for establishing success criteria for key support systems (e.g., cooling water systems).	See SY-B6.
SY-C3	DOCUMENT the key assumptions and key sources of uncertainty associated with the systems analysis.	Include a specific list of key assumptions.	The EPRI report on determining key assumptions and key uncertainties, which was published after the 2003 PRA update, has been reviewed and used for other BWR PRAs. It has been found to be useful in the identification of desirable sensitivity cases and for providing input to decision makers. This task has not been performed for HCGS. Documenting key assumptions is identified as a Supporting Requirement in the ASME PRA Standard (Addendum B) for meeting Capability Category II. This is judged to be primarily a documentation issue and judged to have no impact on EPU evaluation.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
HR-A1	For equipment modeled in the PRA, IDENTIFY, through a review of procedures and practices, those test and maintenance activities that require realignment of equipment outside its normal operational or standby status.	Develop and maintain a list of procedures used to support HRA.	This is judged to be primarily a documentation issue. Maintaining an up-to-date list of the procedures used to support the HRA is judged to be important for the traceability of the PRA model. However, this is judged not to alter the conclusions of the EPU evaluation. Judged to have no impact on EPU evaluation.
HR-A2	IDENTIFY, through a review of procedures and practices, those calibration activities that if performed incorrectly can have an adverse impact on the automatic initiation of standby safety equipment.	See HR-A1.	See HR-A1.
HR-I3	DOCUMENT the key assumptions and key sources of uncertainty associated with the human reliability analysis.	Include a specific list of key assumptions.	The EPRI report on determining key assumptions and key uncertainties, which was published after the 2003 PRA update, has been reviewed and used for other BWR PRAs. It has been found to be useful in the identification of desirable sensitivity cases and for providing input to decision makers. This task has not been performed for HCGS. Documenting key assumptions is identified as a Supporting Requirement in the ASME PRA Standard (Addendum B) for meeting Capability Category II. This is judged to be primarily a documentation issue and judged to have no impact on EPU evaluation.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
DA-C6	DETERMINE the number of plant-specific demands on standby components on the basis of the number of *(a)* surveillance tests *(b)* maintenance acts *(c)* surveillance tests or maintenance on other components *(d)* operational demands. DO NOT COUNT additional demands from post-maintenance testing; that is part of the successful renewal.	Determine the number of plant-specific demands on standby components.	The data update would have a similar impact for both the pre-EPU and the EPU plant configuration. The revised data is judged not to alter the conclusions of the EPU evaluation. Judged to have no impact on EPU evaluation.
DA-C7	BASE number of surveillance tests on plant surveillance requirements and actual practice. BASE number of planned maintenance activities on plant maintenance plans and actual practice. BASE number of unplanned maintenance acts on actual plant experience.	Base number of surveillance tests on plant surveillance requirements and actual practice.	The data update would have a similar impact for both the pre-EPU and the EPU plant configuration. The revised data is judged not to alter the conclusions of the EPU evaluation. Judged to have no impact on EPU evaluation.
DA-C8	When required, USE plant-specific operational records to determine the time that components were configured in their standby status.	Use plant-specific operational records data.	The data update would have a similar impact for both the pre-EPU and the EPU plant configuration. The revised data is judged not to alter the conclusions of the EPU evaluation. Judged to have no impact on EPU evaluation.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
DA-C9	ESTIMATE operational time from surveillance test practices for standby components, and from actual operational data.	Use plant-specific surveillance data.	The operational time is generally not available from the System Managers or Maintenance Rule data and is estimated. The data update would have a similar impact for both the pre-EPU and the EPU plant configuration. The revised data is judged not to alter the conclusions of the EPU evaluation. Judged to have no impact on EPU evaluation.
DA-C15	Data on recovery from loss of offsite power, loss of service water, etc. are rare on a plant-specific basis. If available, for each recovery, COLLECT the associated recovery time with the recovery time being the period from identification of the system or function failure until the system or function is returned to service.	Consider collecting plant specific recovery data.	Generic recovery data for loss of offsite and onsite AC power is used to characterize the PRA models. Recovery is also credited for the Loss of SACS and Loss of Service Water initiating events based on screening evaluations. Recovery is applied based on that these initiating events are generally slow developing events with adequate time for operator mitigation actions. No other recoveries are included. The collection of plant specific recovery data is not considered useful because the data will not be reflective of accident conditions and the data will be sufficiently sparse as to be statistically meaningless. It is recommended that HCGS await further ASME clarification on this item before proceeding.
DA-E3	DOCUMENT the key assumptions and key sources of uncertainty associated with the data analysis.	Include a specific list of key assumptions.	The EPRI report on determining key assumptions and key uncertainties, which was published after the 2003 PRA update, has been reviewed and used for other BWR PRAs. It has been found to be useful in the

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
DA-E3 (cont'd)			identification of desirable sensitivity cases and for providing input to decision makers. This task has not been performed for HCGS. Documenting key assumptions is identified as a Supporting Requirement in the ASME PRA Standard (Addendum B) for meeting Capability Category II. This is judged to be primarily a documentation issue and judged to have no impact on EPU evaluation.
IF-B2	For each potential source of flooding, IDENTIFY the flooding mechanisms that would result in a fluid release. INCLUDE: (a) failure modes of components such as pipes, tanks, gaskets, expansion joints, fittings, seals, etc. (b) human-induced mechanisms that could lead to overfilling tanks, diversion of flow through openings created to perform maintenance; inadvertent actuation of fire suppression system (c) other events resulting in a release into the flood area	Evaluate maintenance induced flooding. EPRI is developing a method to address flood frequencies including maintenance. The current failure rates are judged to encompass maintenance events.	Judged to have no impact on EPU evaluation.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
IF-D5a	GATHER plant-specific information on plant design, operating practices and conditions that may impact flood likelihood (i.e., material condition of fluid systems, experience with water hammer, and maintenance induced floods). In determining the flood initiating event frequencies for flood scenario groups, USE a combination of *(a)* generic and plant-specific operating experience, *(b)* pipe, component, and tank rupture failure rates from generic data sources and plant-specific experience, and *(c)* engineering judgment for consideration of the plant-specific information collected,	See IF-B2.	See IF-B2.
IF-D6	INCLUDE consideration of human-induced floods during maintenance through application of generic data.	See IF-B2.	See IF-B2.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
IF-F2	DOCUMENT the process used to identify flood sources, flood areas, flood pathways, flood scenarios, and their screening, and internal flood model development and quantification. For example, this documentation typically includes: *(a)* flood sources identified in the analysis, rules used to screen out these sources, and the resulting list of sources to be further examined *(b)* flood areas used in the analysis and the reason for eliminating areas from further analysis *(c)* propagation pathways between flood areas and key assumptions, calculations, or other bases for eliminating or justifying propagation pathways *(d)* accident mitigating features and barriers credited in the analysis, the extent to which they were credited, and associated justification *(e)* key assumptions or calculations used in the determination of the impacts of submergence, spray, temperature, or other flood-induced effects on equipment operability *(f)* screening criteria used in the analysis *(g)* flooding scenarios considered, screened, and retained *(h)* description of how the internal event analysis models were modified to model these remaining internal flooding scenarios	Additional documentation detail could be provided.	The internal flood analysis addresses all of the critical items identified. Additional detail could be provided. This robust evaluation is not judged to be affected and will not in turn influence the EPU risk assessment.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
IF-F2 (cont'd)	*(i)* flood frequencies, component unreliabilities / unavailabilities, and HEPs used in the analysis (i.e., the data values unique to the flooding analysis) *(j)* calculations or other analyses used to support or refine the flooding evaluation *(k)* results of the internal flooding analysis, consistent with the quantification requirements provided in HLR QU-D		
QU-E1	IDENTIFY key sources of model uncertainty.	Identify key model uncertainty analyses and sensitivity evaluations consistent with the EPRI guidance.	The EPRI report on determining key assumptions and key uncertainties, which was published after the 2003 PRA update, has been reviewed and used for other BWR PRAs. It has been found to be useful in the identification of desirable sensitivity cases and for providing input to decision makers. This task has not been performed for HCGS. Documenting key assumptions is identified as a Supporting Requirement in the ASME PRA Standard (Addendum B) for meeting Capability Category II. This is judged to be primarily a documentation issue and judged to have no impact on EPU evaluation.
LE-C2a	INCLUDE realistic treatment of feasible operator actions following the onset of core damage consistent with applicable procedures, e.g., EOPs / SAMGs, proceduralized actions, or Technical Support Center guidance.	Include realistic treatment of feasible operator actions following the onset of core damage.	The current HRA for Level 2 may be slightly pessimistic. Judged to have no impact on EPU evaluation.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
LE-C8a	JUSTIFY any credit given for equipment survivability or human actions under adverse environments.	Justify any credit given for equipment survivability.	The credit for equipment under severe accident conditions may be slightly pessimistic. Judged to have no impact on EPU evaluation.
LE-C8b	REVIEW significant accident progression sequences resulting in a large early release to determine if engineering analyses can support continued equipment operation or operator actions during accident progression that could reduce LERF. USE conservative or a combination of conservative and realistic treatment for non-significant accident progression sequences.	Review significant accident progression sequences resulting in a large early release.	The current HRA for Level 2 may be slightly pessimistic. Judged to have no impact on EPU evaluation.
LE-C9a	JUSTIFY any credit given for equipment survivability or human actions that could be impacted by containment failure.	Justify any credit given for equipment survivability.	The credit for equipment under severe accident conditions may be slightly pessimistic. Judged to have no impact on EPU evaluation.
LE-C9b	REVIEW significant accident progression sequences resulting in a large early release to determine if engineering analyses can support continued equipment operation or operator actions after containment failure that could reduce LERF. USE conservative or a combination of conservative and realistic treatment for non-significant accident progression sequences.	Review significant accident progression sequences resulting in a large early release.	The current HRA for Level 2 may be slightly pessimistic. The credit for equipment under severe accident conditions may be slightly pessimistic. Judged to have no impact on EPU evaluation.

Table 9.9-1

2006 HCGS PRA SELF-ASSESSMENT FINDINGS USING ADDENDA B OF ASME PRA STANDARD (SUPPORTING REQUIREMENTS NOT MEETING CAPABILITY CATEGORY II)

Applicable ASME Standard Supporting Requirement	ASME PRA Standard Supporting Requirement (SR) for Capability Category II	Area Not Met	Impact on EPU
LE-G4	DOCUMENT key assumptions and key sources of uncertainty associated with the LERF analysis, including results and important insights from sensitivity studies.	Include a specific list of key assumptions.	The EPRI report on determining key assumptions and key uncertainties, which was published after the 2003 PRA update, has been reviewed and used for other BWR PRAs. It has been found to be useful in the identification of desirable sensitivity cases and for providing input to decision makers. This task has not been performed for HCGS. Documenting key assumptions is identified as a Supporting Requirement in the ASME PRA Standard (Addendum B) for meeting Capability Category II. This is judged to be primarily a documentation issue and judged to have no impact on EPU evaluation.

9.10 Please provide a parametric uncertainty analysis of the OLTP CDF and the CPPU CDF.

Response

The parametric uncertainty analysis of the CLTP CDF[1] and the CPPU CDF is based on the same methodology performed for the base Hope Creek Full Power Internal Events (FPIE) PRA model. This consists of a Monte Carlo simulation of the PRA results (cutsets) with the individual uncertainty distribution for each basic event included. In addition, the use of "Type Codes" allows the correlation effect to also be accounted for in the Monte Carlo simulation. The parametric uncertainty propagation is performed using the commercially available software UNCERT, Version 2.3a (part of the EPRI R&R Workstation).

Core Damage Frequency (CDF) Parametric Uncertainty Distribution

The resulting uncertainty distributions calculated by UNCERT Version 2.3a for the CLTP CDF and the CPPU CDF are shown in Figure 9.10-1 and 9.10-2, respectively. The figures summarize:

- Distribution statistics (e.g., mean, standard deviation, etc.)
- Probability density chart of the CDF

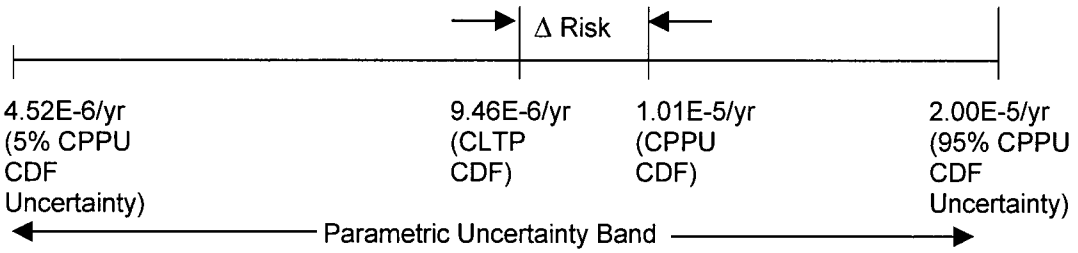
The approximate range factor (RF) for the CDF uncertainty distribution is as follows:

Hope Creek Model	Mean CDF Result	Number of CDF Cutsets	Computed RF[2]
CLTP Model	9.46E-6/yr	33,333	2.2
CPPU Model	1.01E-5/yr	35,568	2.1

One of the aspects of the parametric uncertainty assessments is to show that the range of the CDF uncertainty is large compared to the change in CDF due to EPU.

The following provides this comparison for the CLTP CDF and the CPPU CDF point estimate calculations relative to the CPPU CDF Monte Carlo evaluation:

(1) Note that a parametric uncertainty analysis of the CLTP CDF is provided in lieu of the OLTP CDF.
(2) Range Factor (RF) = (95% upper bound / 5% Lower bound)$^{1/2}$



This comparison is consistent with previous BWR PRA EPU submittals. Therefore, it is concluded that the impact of EPU on the Hope Creek PRA CDF is small relative to the uncertainty range.

Large Early Release Frequency (LERF) Parametric Uncertainty Distribution

For additional information, the same process used for CDF is also used for LERF. The resulting uncertainty distributions calculated by UNCERT Version 2.3a for the CLTP LERF and the CPPU LERF are shown in Figure 9.10-3 and 9.10-4, respectively. The figures summarize:

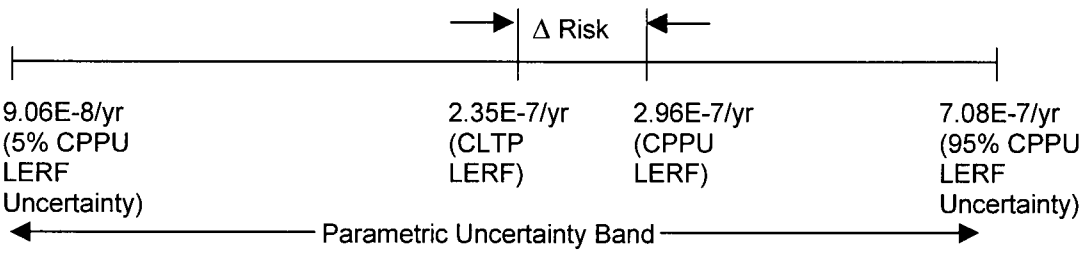
- Distribution statistics (e.g., mean, standard deviation, etc.)
- Probability density chart of the LERF

The approximate range factor (RF) for the LERF uncertainty distribution is as follows:

Hope Creek Model	Mean LERF Result	Number of LERF Cutsets	Computed RF[1]
CLTP Model	2.35E-7/yr	1474	2.7
CPPU Model	2.96E-7/yr	1912	2.8

One of the aspects of the parametric uncertainty assessments is to show that the range of the LERF uncertainty is large compared to the change in LERF due to EPU.

The following provides this comparison for the CLTP LERF and the CPPU LERF point estimate calculations relative to the CPPU LERF Monte Carlo evaluation:



(1) Range Factor (RF) = (95% upper bound / 5% Lower bound)$^{1/2}$

This comparison is consistent with previous BWR PRA EPU submittals. Therefore, it is concluded that the impact of EPU on the Hope Creek PRA LERF is small relative to the uncertainty range.

Conclusions

The calculated parametric uncertainty distribution shows significant overlap between the CLTP (i.e., pre-EPU) and CPPU (i.e., EPU) uncertainty distributions for both the CDF and LERF metrics. (See Figures 9.10-1 through 9.10-4.)

The parametric uncertainty distribution is relatively narrow because there are a large number of contributing cutsets. This has previously been shown to lead to a narrowing of the overall uncertainty distribution. [9.10-1]

Reference

9.10-1 Burns, E.T. and Lee, L.K., "Uncertainty: Can Risk Informed Regulation Survive the Challenge?", International Meeting on Probabilistic Safety Assessment, pp 1565-1575, Park City, Utah, September 29 – October 3, 1996.

Figure 9.10-1

Level 1 CDF Parametric Uncertainty Analysis for CLTP Plant

Mean 9.46E-06
5% 4.14E-06
50% 8.11E-06
95% 1.92E-05
Std. Dev. 5.50E-06
Samples 50,000

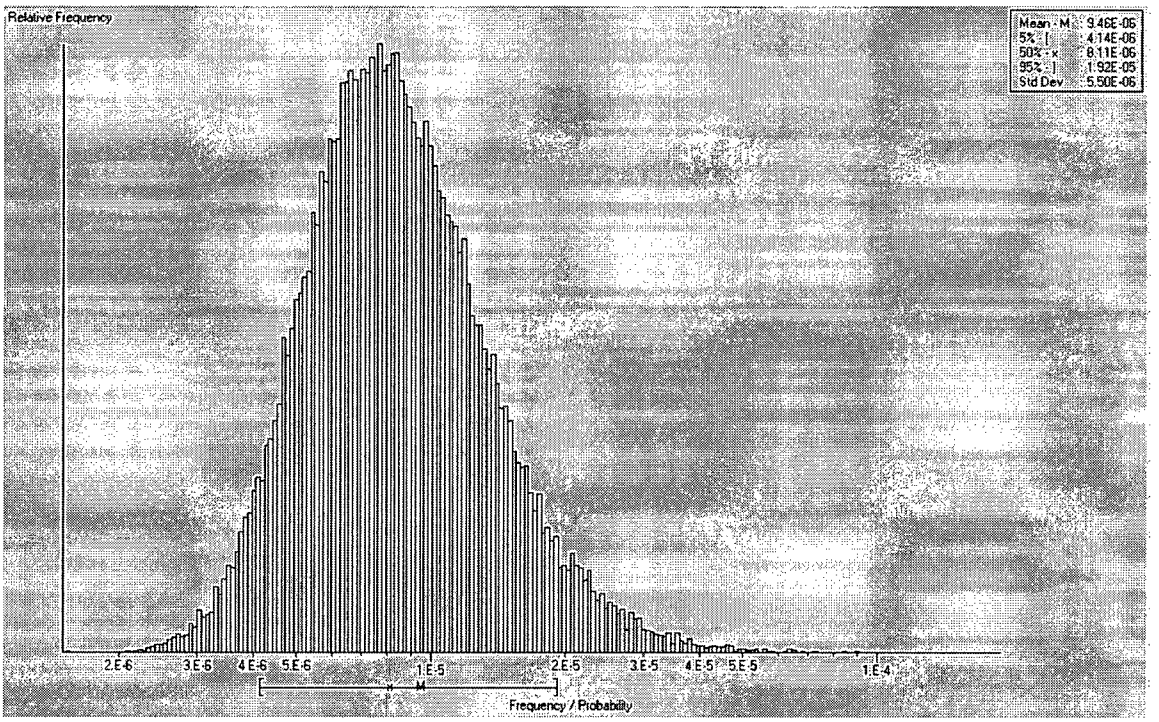


Figure 9.10-2

Level 1 CDF Parametric Uncertainty Analysis for CPPU Plant

Mean	1.01E-05
5%	4.52E-06
50%	8.71E-06
95%	2.00E-05
Std. Dev.	5.78E-06
Samples	50,000

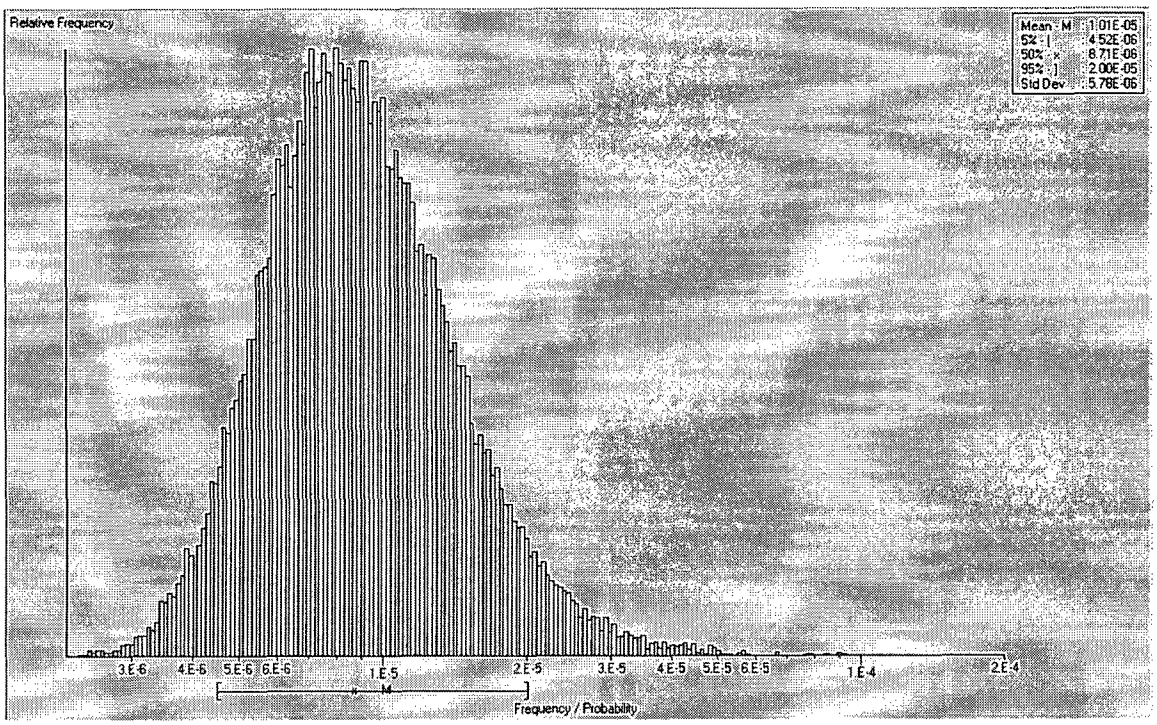


Figure 9.10-3

Level 2 LERF Parametric Uncertainty Analysis for CLTP Plant

Mean 2.35E-07
5% 7.50E-08
50% 1.86E-07
95% 5.47E-07
Std. Dev. 1.90E-07
Samples 50,000

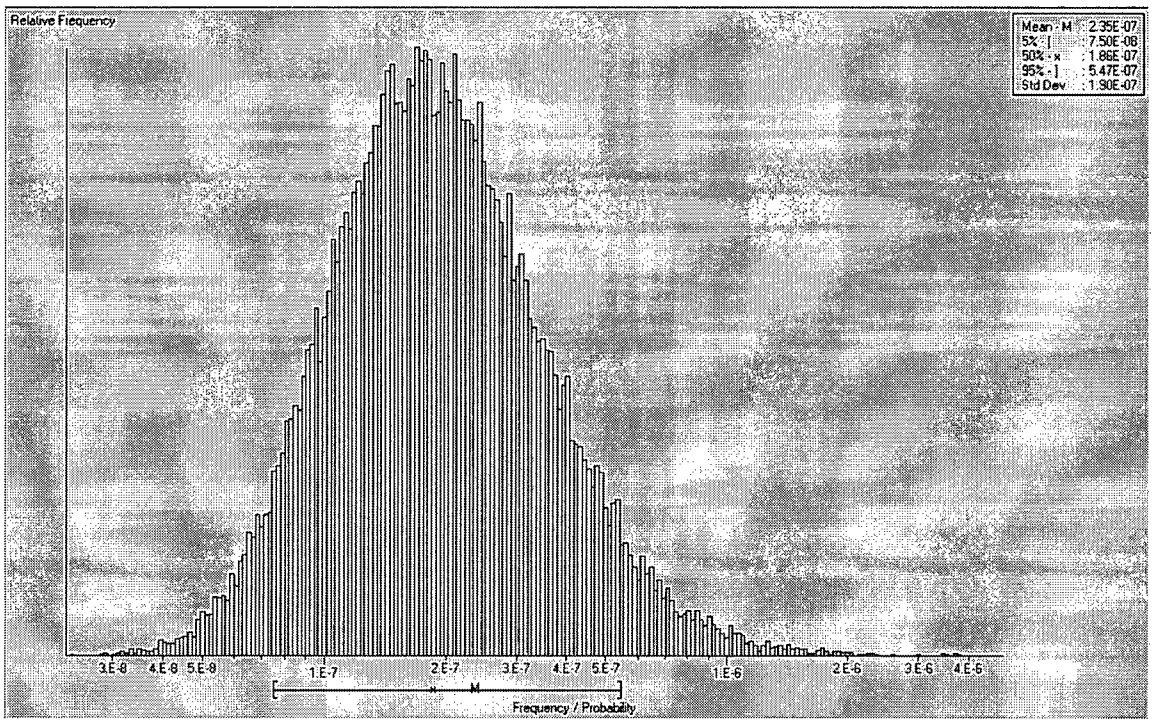
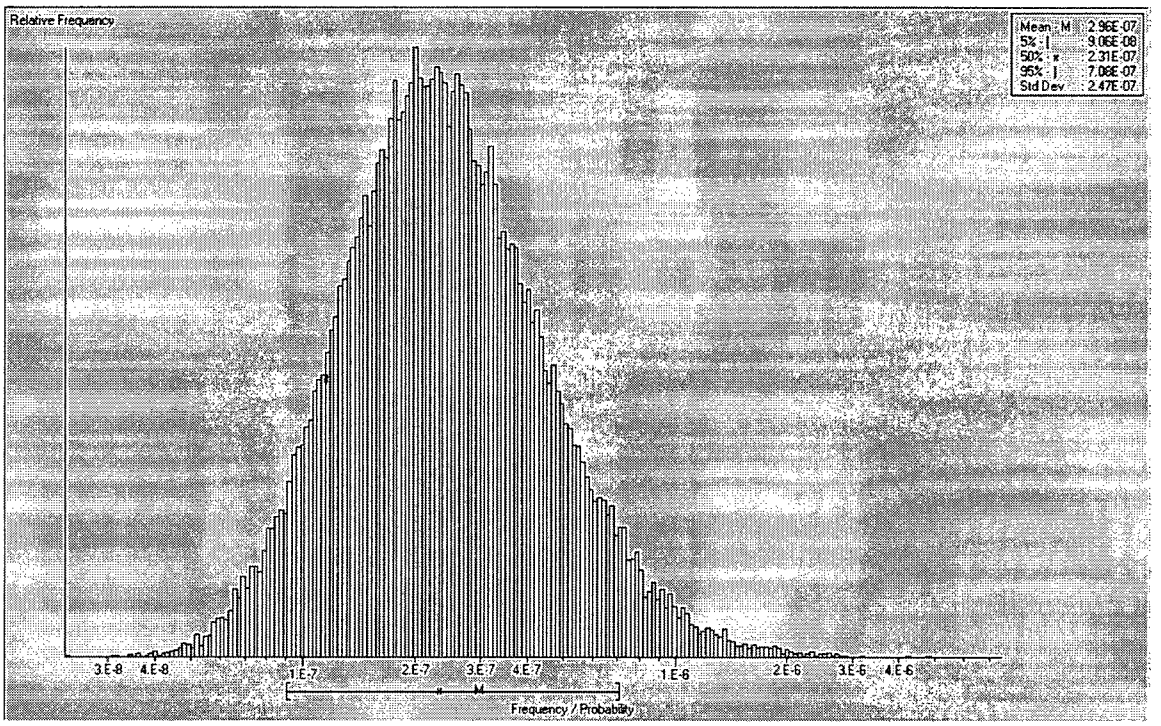


Figure 9.10-4

Level 2 LERF Parametric Uncertainty Analysis for CPPU Plant

Mean 2.96E-07
5% 9.06E-08
50% 2.31E-07
95% 7.08E-07
Std. Dev. 2.47E-07
Samples 50,000



10) Instrumentation & Controls Branch (EICB)

10.1 The license amendment request (LAR) proposes Technical Specifications (TS) changes associated with instrument set point(s) for the EPU, please provide the following for each set point to be added or modified:

a) Setpoint Calculation Methodology: Provide documentation (including sample calculations) of the methodology used for establishing the limiting nominal set point and the limiting acceptable values for the As-Found and As-Left set points as measured in periodic surveillance testing as described below. Indicate the related Analytical Limits and other limiting design values (and the sources of these values) for each set point.

Response

The proposed HCGS Technical Specification (TS) set point changes with the associated Nominal Trip Setpoint (NTSP), Allowable Value(AV), and Analytical Limit (AL) are listed in the table below. The completed setpoint calculations are provided in Attachments 3 and 4.

Trip Function	NTSP	Allowable Value	Analytical Limit	Source
APRM Flow Biased Simulated Thermal Power - Upscale (Scram)	0.57(W-ΔW) + 58% Clamp @ 113.5%	0.57(W-ΔW) + 61% Clamp @ 115.5%	Note	SC-SE-0002-2
APRM Flow Biased Neutron Flux - Upscale (Rod Block)	0.57(W-ΔW) + 53% Clamp @ 108%	0.57(W-ΔW) + 56% Clamp @ 111%	Note	SC-SE-0002-2
APRM Neutron Flux - Upscale, Setdown (Scram)	14%	19%	Note	SC-SE-0002-2
APRM Neutron Flux - Upscale, Startup (Rod Block)	11%	13%	Note	SC-SE-0002-2
Main Steam Line Flow - High	162.8 psid	169.3 psid	176.2 psid (140% Main Steam Flow)	SC-SM-0001-1

Note: HCGS does not have ALs for this setpoint. No credit is taken in any safety analysis for the flow referenced setpoints.

Under the HCGS setpoint program, a setpoint calculation establishes the calibration design requirements for the instrument channel under the guidance of Technical Standard HC.DE-TS.ZZ-1001. HCGS TS list both a Nominal Trip Setpoint (NTSP) and an Allowable Value (AV). Hope Creek calibrates its instruments around the NTSP.

For the Main Steam High flow setpoint, surveillance procedures require that TS setpoint related instruments be left within a band around the NTSP

(or calibration values for a transmitter). The maximum deviation within which a device can be left is called the "Desired Range" in the calibration procedure and "Recal Tolerance" in the setpoint calculation. The Recal Tolerance is defined by the Square Root of the Sum of the Squares (SRSS) of the accuracy and the calibration tolerance. An Acceptable Value is also established to provide the limiting value where corrective action would be required. The Acceptable Value is calculated by Square Root Sum of Squares (SRSS) of the component calibration effect, drift and accuracy (at normal conditions). The Total Loop Allowance (TLA) is calculated by combining instrument loop accuracy, instrument loop drift, and loop calibration error by SRSS and algebraically combining the Process Measurement Accuracy (PMA).

The CPPU simplified setpoint methodology, as described in NEDC-33004P-A, "Licensing Topical Report, Constant Pressure Power Uprate," Revision 4, July 2003, was applied for the APRM NTSPs. According to this simplified methodology, the change in ALs ("delta AL") can be applied to the current NTSPs to obtain the new NTSPs as long as the instruments in the loop are not replaced. The simplified method merely assumes that the instrument errors remain the same. So any AL/NTSP margin that depends only on the instrument errors, is unchanged, irrespective of what setpoint methodology was used to calculate the margin. The AL/NTSP margin and the AV/NTSP margin are both based on instrument errors and therefore the simplified method can be applied to the AV/NTSP margin.

Currently, HCGS APRM Flow Biased setpoints and APRM setdown setpoints do not have ALs, only AVs. The AVs for EPU were simply rescaled to the EPU 115% power, and the margin between AV and NTSP is based on instrument error. Therefore, using the change in AV to calculate the change in NTSP is justified by the simplified method, as long as the basic instrument and its errors are unchanged.

APRM TS setpoint changes based on the CPPU simplified setpoint methodology were reviewed and approved previously for HCGS in Reference 10.1.a-1.

<u>Reference</u>

10.1.a-1 Hope Creek Generating Station - Amendment No. 163 (TAC No. MC3390), February 8, 2006

b) For set points that are not determined to be Safety Limit (SL)-related: Describe the measures to be taken to ensure that the associated instrument channel is capable of performing its specified safety functions in accordance with applicable design requirements and associated analyses. Include in your discussion information on the controls you

employ to ensure that the as left trip setting after completion of periodic surveillance is consistent with your set point methodology. If the controls are located in a document other than the TS (e.g., plant test procedure), describe how it is ensured that the controls will be implemented.

Response
For TS setpoints that are not SL-related, the measures taken to ensure that the associated instrument channel is capable of performing its specified safety function are accomplished by two complementing HCGS processes.

Design Process
In the design process, setpoint calculations are prepared to establish the calibration design requirements of the non-SL related setpoints. Design inputs are documented in the setpoint calculation to ensure design requirements are captured. The setpoint calculations determine the NTSP and setpoint margin to the allowable value and analytical limit where one is available. The setpoint calculation is prepared, peer reviewed and if safety related, Independently verified under the PSEG process for control of design analyses. This process ensures that the nominal trip setpoint satisfies design requirements and that implementing documents are identified and revised accordingly prior to calibration.

Implementation
The instrument channel calibration is performed by qualified personnel using approved surveillance procedures. Calibration tolerances are documented in the implementing surveillance procedures.

The controls employed to ensure that the setpoints established after completing periodic surveillances satisfy HCGS requirements reside in HCGS procedures. At the conclusion of the surveillance tests, the HCGS procedures do not permit the trip setpoint to be outside of the Desired Range (Recal Tolerance). (See Figure 10.1.b-1 for the Main Steam High Flow graphical setpoint relationship). This verifies that the instrument channel is calibrated within design requirements, therefore ensuring that the instrument can perform its specified safety function.

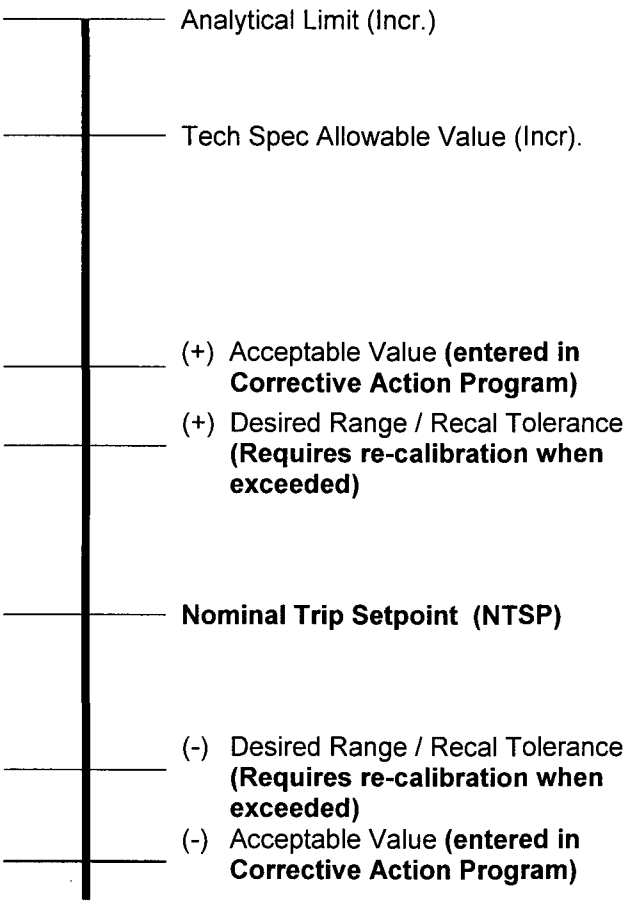


Figure 10.1.b-1 Main Steam High Flow Setpoint Relationship (Increasing process)

10.2 Provide the justification for removal of Turbine First Stage Pressure from the TSs. This justification should be based on how this instrumentation function does not meet the four criteria provided in Title 10 of the Code of Federal Regulations (10 CFR) 50.36(c)(2)(ii).

Response

The turbine stop valve (TSV) closure and the turbine control valve (TCV) fast closure reactor protection system (RPS) trip functions and the end-of-cycle recirculation pump trip (EOC-RPT) are bypassed automatically when thermal power is less than 30% of rated thermal power (P_{bypass}). Turbine first stage pressure is monitored to provide the interlocks for bypassing the RPS trip functions and the EOC-RPT.

Both P_{bypass} and the associated turbine first stage pressure values for the currently installed high-pressure turbine are in the HCGS Technical Specifications (TS). P_{bypass} is being changed to 24% for EPU implementation. In addition, modifications to the high-pressure turbine will change the relationship of turbine first stage pressure to reactor power. The proposed change would change the TS value for P_{bypass} to account for EPU. The P_{bypass} value will be retained within and controlled by Hope Creek Technical Specification; however, the details of the turbine first stage pressure value would be removed from the TS.

TS Limiting Condition for Operation (LCO) 3.3.1 requires that the TSV closure and the TCV fast closure reactor protection system trip functions be operable in Operational Condition 1. The specified applicable operational conditions in TS Table 3.3.1-1 are modified by a note stating that these trip functions shall be automatically bypassed when turbine first stage pressure is less than or equal to 159.7 psig equivalent to thermal power less than 30% of rated thermal power. The note also states that a setpoint of less than or equal to 135.7 psig is used to allow for instrument accuracy, calibration, and drift.

LCO 3.3.4.2 requires that EOC-RPT be operable in Operational Condition 1 when thermal power is greater than or equal to 30% of rated thermal power. TS Table 3.3.4.2-1 is modified by a note stating that these trip functions shall be automatically bypassed when turbine first stage pressure is less than or equal to 159.7 psig equivalent to thermal power less than 30% of rated thermal power. The note also states that a setpoint of less than or equal to 135.7 psig is used to allow for instrument accuracy, calibration, and drift.

The turbine first stage pressure values in TS Tables 3.3.1-1 and 3.3.4.2-1 are details of system design that are not required by 10 CFR 50.36(c)(2)(ii) to be included in the TS as discussed below:

1. Turbine first stage pressure instrumentation is not used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

2. Turbine first stage pressure is not a process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of or presents a challenge to the integrity of a fission product barrier. P_{bypass} is an initial condition for some transient analyses and is retained in TS Tables 3.3.1-1 and 3.3.4.2-1.

3. Turbine first stage pressure instrumentation is not a structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of or presents a challenge to the integrity of a fission product barrier.

4. Turbine first stage pressure instrumentation is not a structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

Removal of the turbine first stage pressure values from the TS is consistent with NUREG-1433, "Standard Technical Specifications, General Electric Plants, BWR/4." The turbine first stage pressure setpoint will be controlled in accordance with plant procedures and will be verified during post-installation testing.

10.3 Section 5.1 of the NRC staff's safety evaluation of General Electric Nuclear Energy Licensing Topical Report NEDC-33004P, "Constant Pressure Power Uprate," dated March 31, 2003, require that a plant-specific submittal should address all CPPU related changes to instrumentation & controls, such as scaling changes, changes to upgrade obsolescent instruments and changes to control philosophy. Provide this information for staff's review.

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 for EPU are listed in Table 5-3 of NEDC-33076P, Revision 2 (Attachment 4 to Reference 1). In addition to these changes, the reactor core isolation cooling (RCIC) turbine exhaust pressure trip setpoint is being changed to ensure system availability for the duration assumed for the Station Blackout (SBO) event.

The plant-specific CPPU related instrument scaling changes are listed in Table 5-2 of NEDC-33076P, Rev. 2 (Attachment 4 to Reference 1).

Instrument replacements for EPU are listed in Table 5-4 of NEDC-33076P, Rev. 2.

There are no changes to control philosophy associated with EPU.

3) BWR Systems Branch (SBWB)

The NRC staff plans to perform a limited set of audit calculations for Hope Creek Chapter 15 safety analyses at the proposed increased power rating using the RELAP5 computer code. The computer model for a Boiling Water Reactor (BWR) type 4 plant will be modified to represent a mixed core loss-of-coolant accident (LOCA) analysis for Hope Creek. In order to enable the NRC staff to adequately perform this task, please provide the following information:

3.47 For postulated large and small recirculation line LOCAs for Cycle 15 (initial EPU core), please provide and justify the limiting axial power shapes employed in the Appendix K evaluation determining PCT. For different exposures, select bundles with limiting axial power peaking operating with bottom peaked, double-hump or mid-peaked, and top peaked axial power distributions. Provide the peak fuel bundle to average fuel bundle power ratio (radial peaking factor). Provide the peak fuel rod to peak bundle power ratio (local peaking factor). Provide average and hot bundle exit void fraction.

Please provide above information for General Electric (GE14) fuel and Westinghouse (SVEA-96+) nuclear fuel. For SVEA-96+ fuel you alternatively could provide detailed justification demonstrating that the fuel would not be limiting in regards to peak cladding temperatures (PCT) in your LOCA analysis for Cycle 15. In addition,

a) for SVEA-96+ fuel, if determined to be PCT limiting, provide the following information:

Fuel rod diameter for an average and a hot rod
Cladding thickness
Gap gas mole fractions for an average and a hot rod
Gap thickness for an average and a hot rod
Gap internal pressure for an average rod and for the hot rod
gap conductance
Cladding heat capacity vs temperature
Cladding thermal conductivity vs temperature
Fuel heat capacity vs temperature
Fuel thermal conductivity vs temperature
Channel box heat capacity vs temperature
Channel box thermal conductivity vs temperature
Temperature distribution within average and hot channels. Temperature distribution within a hot rod.
Channel box dimensions and thickness

b) for GE 14 fuel, provide the following information:

Gap gas mole fractions for an average and a hot rod
Gap internal pressure for an average rod and for the hot rod
gap conductance
Temperature distribution within average and hot channels. Temperature distribution within a hot rod.

c) Reactor Kinetics Information as follows:

Total power histories (include GE and SVEA in the mixed core of Cycle 15) after scram in the limiting LOCA analysis.

d) Fuel Bundle Information for GE-14 and SVEA-96+ fuel as follows:

Cross sectional drawing of the fuel bundles showing rod spacing and pitch.
Location of the highest power rod
Location and dimensions of water rods

e) Fuel Bundle Pressure drop information as follows:

Provide flow loss coefficients as a function of axial height for the GE14 and SVEA-96+ fuel bundles.

Response

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]] The axial power shapes used for the Appendix K analysis at EPU power and MELLLA flow are shown in Figure 3.47-1 for GE14 and Figure 3.47-2 for SVEA; the top-peaked power shapes are typical of what is used when the axial peaking is the same as that used in the mid-peaked analysis.

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The limiting GE14 fuel will be operating at peak exposure values consistent with the maximum (or near maximum) LHGR limit, and therefore consistent with the limiting (or near limiting) PCT, during Cycle 15. Therefore, it is expected that the SVEA PCT will be bounded by the GE14 PCT for operating cycle 15.

Response to Part a

As discussed above the SVEA PCT is expected to be bounded by the GE14 PCT for operating cycle 15.

Response to Part b

For gas composition and internal pressures see Table 3-47b-1 and Table 3-47b-2.

The cladding temperature distributions for the hot rod in the hot bundle and the average rod in the average bundle are provided in Figures 3-47b-1 through 3-47b-4. These are the cladding surface temperatures for the hot rod in the hot bundle and the average rod in the average bundle. The normal SAFER output does not include the other rod types or the fuel temperatures because the fuel temperatures are usually not limiting in LOCA events.

Response to Part c
The SAFER evaluation uses the same nominal and Appendix K decay heat curves for all fuel types. These curves are provided in Figure 3-1 of NEDC-33172P. The tabular data used for these curves are shown in Table 3-47c-1.

Response to Part d
The cross sectional drawings of the fuel bundles and dimensions for GE14 fuel are shown in Figure 3.47d-1 and Table 3.47d-1. The location and dimension of water rods are also included. As discussed above the SVEA PCT is expected to be bounded by the GE14 PCT for operating cycle 15.

The highest power rod is specific to the nuclear design of the bundle (i.e., enrichment and/or gadolinia distribution) as well as its exposure, its control state, and the fluid conditions (void fraction). It is very difficult to designate a single rod as the highest power rod since it changes position as exposure is accumulated and fluid conditions change. Instead, the local peaking factors (highest rod power divided by average rod power) are provided in Figures 3.47d-3 thru 3.47d-14 for all relevant lattices of Cycle 15 showing the highest power rod at each exposure and void fraction.

Note that Cycle 15 GE14 fuel was designed based on 3722 MWth power level (~11.5% uprate) and fuel designed with the proposed 15% increase in power (3840 MWth) would likely result in slightly different local peaking in order to accommodate the additional power.

Response to Part e
The pressure loss coefficients as a function of axial height for the GE14 fuel bundles are provided in Table 3.47e-1. As discussed above the SVEA PCT is expected to be bounded by the GE14 PCT for operating cycle 15.

Table 3.47b-1 GE14 Hot Rod Parameters

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Table 3.47b-1 GE14 Hot Rod Parameters (continued)

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Table 3.47b-2 GE14 Average Rod Parameters

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Table 3-47c-1
Nominal and Appendix K Decay Heat

Time	Post-Scram Power Ratio	
seconds	Nominal	Appendix K
0	1.00000	1.00000
0.1	0.98250	-
0.15	0.95330	-
0.2	0.92400	0.92605
0.4	0.73950	0.74516
0.6	0.58420	-
0.8	0.48790	0.49790
1	0.33360	-
1.5	0.24220	-
2	0.15100	0.16624
4	0.07051	0.08666
6	0.05788	-
7	-	0.07243
8	0.05380	-
10	0.04980	0.06594
15	0.04615	-
20	0.04329	0.05810
30	-	0.05448
40	0.03802	0.05087
60	0.03517	0.04694
80	0.03306	0.04438
100	0.03170	0.04257
150	0.02934	0.03918
200	0.02780	-
250	-	0.03455
400	0.02440	0.03085
600	0.02247	-
700	-	0.02691
800	0.02107	-
1000	0.01995	0.02454
1500	0.01789	-
2000	0.01643	-
4000	0.01323	-
6000	0.01170	-
8000	0.01079	-
10000	0.01015	0.01298

Table 3.47d-1. GE14 Lattice Dimensions

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Table 3.47e-1. Pressure Loss Coefficients

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Figure 3.47-1. Axial Power Shapes for GE14 Fuel with Appendix K Assumptions at EPU Power and MELLLA Flow

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Figure 3.47-2. Axial Power Shapes for SVEA Fuel with Appendix K Assumptions at EPU Power and MELLLA Flow

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Figure 3.47b-1. Cladding Temperatures for the GE14 Hot Bundle Upper Nodes – Appendix K DBA Break at EPU Power and MELLLA Flow with Battery Failure

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Figure 3.47b-2. Cladding Temperatures for the GE14 Hot Bundle Lower Nodes – Appendix K DBA Break at EPU Power and MELLLA Flow with Battery Failure

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Figure 3.47b-3. Cladding Temperatures for the GE14 Average Bundle Upper Nodes – Appendix K DBA Break at EPU Power and MELLLA Flow with Battery Failure

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Figure 3.47b-4. Cladding Temperatures for the GE14 Average Bundle Lower Nodes – Appendix K DBA Break at EPU Power and MELLLA Flow with Battery Failure

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Figure 3.47d-1. GE14 Lattice Cross-Section

Figure 3.47d-2
Not Used

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Figure 3.47d-3. GE14 Lattice 7715 Local Peaking Factors (Uncontrolled)

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Figure 3.47d-4. GE14 Lattice 7716 Local peaking factors (uncontrolled)

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Figure 3.47d-5. GE14 Lattice 7718 Local peaking factors (uncontrolled)

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Figure 3.47d-6. GE14 Lattice 7721 Local peaking factors (uncontrolled)

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Figure 3.47d-7. GE14 Lattice 7722 Local peaking factors (uncontrolled)

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Figure 3.47d-8. GE14 Lattice 7724 Local peaking factors (uncontrolled)

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Figure 3.47d-9. GE14 Lattice 7727 Local peaking factors (uncontrolled)

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Figure 3.47d-10. GE14 Lattice 7728 Local peaking factors (uncontrolled)

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Figure 3.47d-11. GE14 Lattice 7730 Local peaking factors (uncontrolled)

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Figure 3.47d-12. GE14 Lattice 7733 Local peaking factors (uncontrolled)

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Figure 3.47d-13. GE14 Lattice 7734 Local peaking factors (uncontrolled)

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Figure 3.47d-14. GE14 Lattice 7736 Local peaking factors (uncontrolled)

3.48 For the maximum power fuel bundles, provide the thermal radiation emissivites and view factors to be used in evaluation of radiation heat transfer during recovery from a LOCA at the CPPU conditions.

Response
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]] The SAFER input RES(M,N) is the value of the bracketed term in the denominator of Equation 4-37 and 4-38 of Attachment 1. The radiation resistances used in SAFER for GE14 fuel are:

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Where
RES(N,M) is the resistance to radiation between the rods and the channel wall (dimensionless).

RES(1,1) = Hot rod to dry average rod
RES(1,2) = Hot rod to wet average rod
RES(2,1) = Average rod to dry channel wall
RES(2,2) = Average rod to wet channel wall
RES(3,1) = Channel wall to dry average rod
RES(3,2) = Channel wall to wet average rod

The radiation resistances used in SAFER for SVEA fuel are:

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Attachment 1 to RAI 3.48
Description of SAFER Thermal Radiation Model

NEDO-30996-A

The experiments were performed with an empty bundle and no steam injection. The heated rods are, therefore, besides radiation heat transfer, cooled by steam updraft generated from vaporization of spray water.

During a transient, higher convective heat transfer is expected as additional steam is generated from the lower plenum and the partially empty core due to continuous depressurization and stored heat removal. Therefore, the core spray correlation (Equation 4-36) is used as a lower bound value for the SAFER steam cooling calculation.

4.6.7 Radiation Heat Transfer

The complex radiation heat transfer paths between the various rods and the surrounding channel and between the rods themselves are modeled in a simplified, approximate manner in SAFER. For SAFER application, all the fuel rods inside a fuel assembly are represented by an average power rod calculation. The radiation heat transfer between the rods and the channel wall is calculated using an equivalent radiation heat transfer coefficient given by,

$$H_{A-C} = \frac{\sigma\left(T_A^4 - T_C^4\right)}{(T_A - T_{sat})\left[\frac{(1-\varepsilon_A)}{\varepsilon_A} + \frac{1}{F_{AC}} + \frac{(1-\varepsilon_C)}{\varepsilon_C}\left(\frac{A_A}{A_C}\right)\right]} \qquad (4\text{-}37)$$

F_{AC} is a geometry dependent view factor and is defined as,

$$F_{AC} = \frac{1}{N}\sum_{n=1}^{N} F_n$$

with

N = total number of fuel rods inside the fuel assembly

$$F_n = \frac{\text{sum of radiation incident angles from rod "n" to channel wall}}{360°}$$

where subscript A refers to the average power rod and subscript C refers to the channel wall.

An additional high power fuel rod calculation is performed by SAFER to simulate the peak cladding temperature rod response. For high temperature transients, peak cladding temperature occurs in an interior rod (as observed in other detailed core heatup models, i.e., CHASTE and CORECOOL), where it is shielded from the relatively low temperature channel wall by the surrounding rods. Furthermore, high temperatures are also found in the immediate neighboring rods. In SAFER, for the purpose of radiation heat transfer calculation, the peak cladding temperature rod is represented by a rod group in the central region of the fuel assembly surrounded by the average power fuel rods as illustrated in Figure 4-7. The radiation heat transfer coefficient for the high power rod is then given by

$$H_{H-A} = \frac{\sigma\left(T_H^4 - T_A^4\right)}{(T_H - T_{sat})\left[\frac{(1-\epsilon_H)}{\epsilon_H} + \frac{1}{F_{HA}} + \frac{(1-\epsilon_A)}{\epsilon_A}\left(\frac{A_H}{A_A}\right)\right]} \qquad (4\text{-}38)$$

where F_{HA} is the mean view factor for the interior rod group and is obtained by comparison with CORECOOL. In both Equations 4-37 and 4-38, emissivity (ϵ) changes from a value of 0.67 to 0.96 as the surface is wetted by a falling film. In addition, water is vaporized from the film as radiative heat is absorbed.

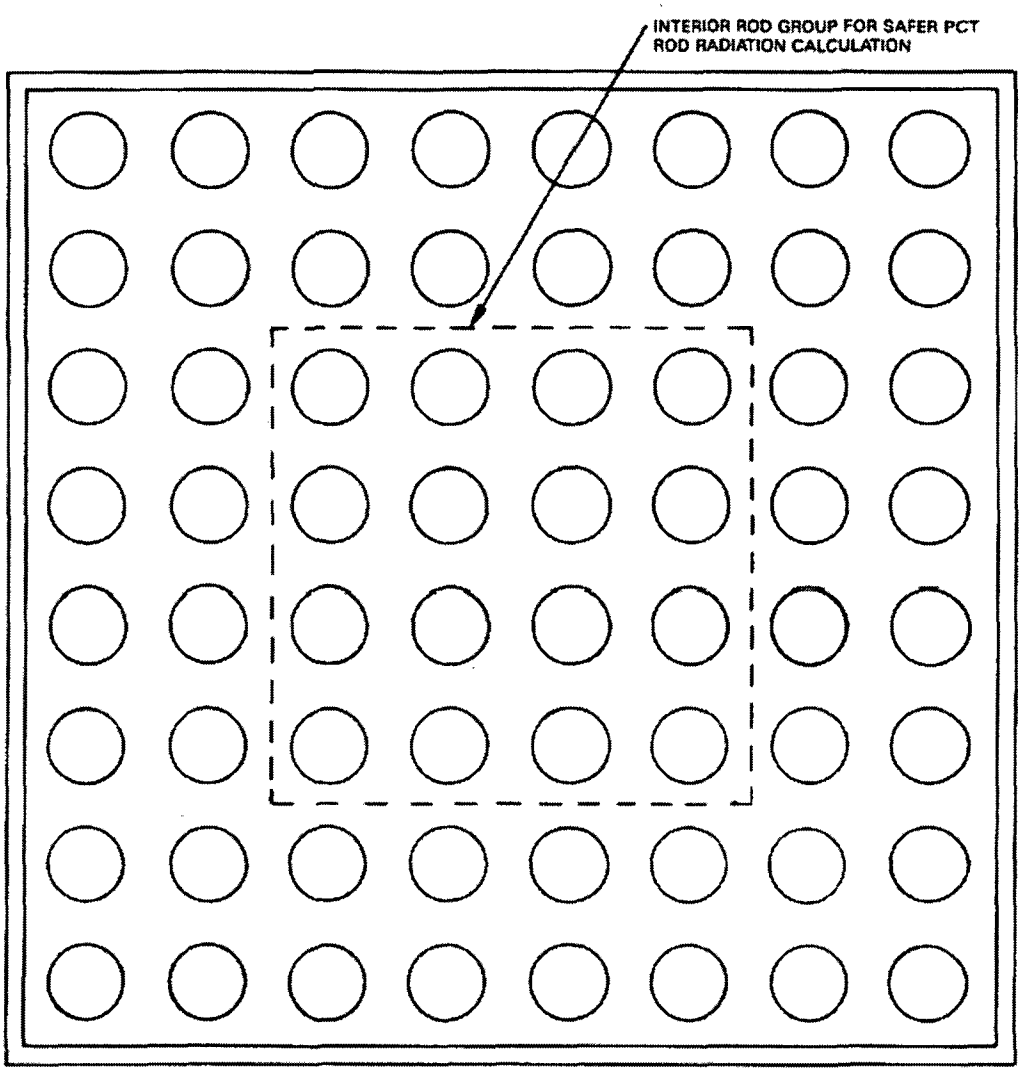

Figure 4-7. Fuel Assembly for Radiation Heat Transfer Model

3.49 For a postulated recirculation pump suction break, at the CPPU conditions, provide the equivalent heat transfer coefficient for radiation heat transfer as a function of time for the highest temperature location of the hottest fuel rod. This information is contained in Figure B-2g of GE Nuclear Energy, Topical Report, (NEDC-33172), "GE LOCA analysis for Hope Creek EPU," but the figure is difficult to read. Please provide a more legible figure.

Response

Figure B-2g of NEDC-33172 contains the heat transfer coefficients for SVEA fuel, but it was agreed that this response would also provide the requested information for GE14 fuel, which would correspond to Figure B-2d. To provide more legibility, only the radiation heat transfer coefficient for the highest PCT node (Node 6) is plotted for the DBA break in Figure 3.49-1 for GE14 and Figure 3.49-3 for SVEA fuel. Similar results are provided for the limiting small break, 0.08 ft^2 in Figure 3.49-2 for GE14 and Figure 3.49-4 for SVEA fuel. These results are for the battery failure at 3917 MWt using Appendix K assumptions. The DBA break is at 94.8% of rated core flow and the small break is at rated core flow.

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Figure 3.49-1. Log of GE14 Radiation Heat Transfer Coefficient for DBA Break with Battery Failure at 3917 MWt and 94.8% Flow

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Figure 3.49-2. Log of GE14 Radiation Heat Transfer Coefficient for 0.08 ft2 Break with Battery Failure at 3917 MWt and 100% Flow

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Figure 3.49-3. Log of SVEA Radiation Heat Transfer Coefficient for DBA Break with Battery Failure at 3917 MWt and 94.8% Flow

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Figure 3.49-4. Log of SVEA Radiation Heat Transfer Coefficient for 0.08 ft2 Break with Battery Failure at 3917 MWt and 100% Flow

3.50 For a postulated recirculation pump suction break at the CPPU conditions, provide a graph of drywell pressure as a function of time.

Response
For the SAFER analyses, the drywell pressure is assumed to remain at 14.7 psia throughout the LOCA event.

3.51 Figures B-2e and B-5e of NEDC-33172 provide the Emergency Core Cooling (ECC) flows for the limiting large and small break sizes at the CPPU conditions. The figures do not distinguish how much Low Pressure Core Injection (LPCI) flow reaches each recirculation loop. Please provide this information. In addition, provide LPCI and High Pressure Core Injection (HPCI) head-flow curves assumed in the LOCA analyses. Provide the capacity of the Automatic Depressurization System (ADS) valves assumed in the analyses in pounds mass per hour (lbs/hr) and pounds per square inch absolute (psia).

Response
The LPCI flow is not injected into the recirculation line in the Hope Creek plant. LPCI flow is injected into the bypass region within the shroud in a manner that is similar to the BWR/5 and BWR/6 plants. Figures B-2e and B-5e are plots of the SAFER output and show the flow injected within the shroud. The limiting single failure is the battery failure, so HPCI is assumed unavailable; however, low-pressure core spray also provides inventory makeup. The flow injected into the shroud from one LPCI system is shown in Figure 3.51-1 as a function of differential pressure between the vessel and drywell. Figure 3.51-1 also provides a similar curve for the flow injected into the shroud by one low-pressure core spray system. The low-pressure core spray has a pressure permissive of 425 psig before the injection valve will open; the LPCI pressure permissive for the injection valve opening is 360 psig.

The HPCI system in Hope Creek injects flow through the core spray piping in addition to the injection into the feedwater line. The HPCI system provides a constant 5600 gpm over the pressure range from 200 psid to 1141 psid, of which 2000 gpm is injected through the core spray piping.

One ADS valve has a minimum flow of 800,000 lb/hr at 1125 psig (1140 psia).

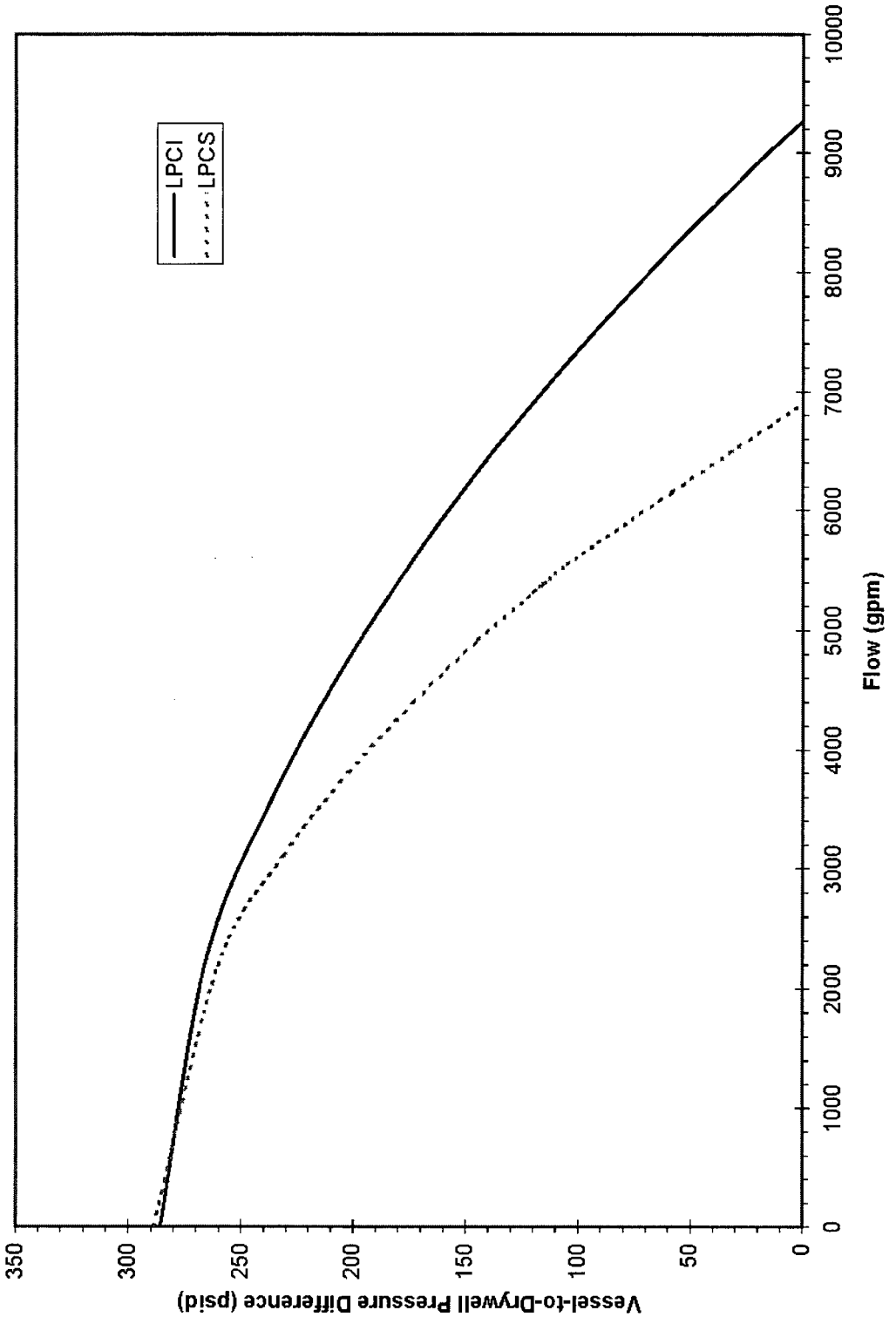

Figure 3.51-1. ECCS Flow Rates Into Shroud

3.52 Provide the sequence events table for the Appendix K limiting Design Basis Accident large-break and small-break LOCAs at the CPPU conditions. They should identify all trip signals and delays such as reactor scram and Emergency Core Cooling Systems injection.

Response

The sequence of events for the limiting large break (DBA break with battery failure at 3917 MWt and 94.8% core flow) using Appendix K assumptions is shown in Table 3.52-1. The sequence of events for the limiting small break (0.08 ft^2 break with battery failure at 3917 MWt and 100% core flow) using Appendix K assumptions is shown in Table 3.52-2. These tables of event sequence show the trip signals and delays of the ECCS that are available for the assumed single failure along with those of other reactor equipment affecting the LOCA response.

Table 3.52-1
Sequence of Events for DBA Break with Battery Failure at 3917 MWt and 94.8% Flow

EVENT	TIME (sec)
Break Occurs	0.0
High Drywell Pressure Trip (assumed)	0.0
Recirculation Pumps Trip	0.0
Feedwater Pumps Trip	0.0
Scram Initiated	0.0
Signal to Start CS	1.0
Signal to Start LPCI	1.0
Signal to Start Diesel Generator	1.0
Low-Low Water Level (L1) Trip	4.5
Feedwater Flow Reaches Zero	5.0
Turbine Admission Valve Closes	5.4
MSIVs Close	10.0
CS IV Pressure Permissive Reached	20.9
LPCI IV Pressure Permissive Reached	23.0
CS Injection Valve Fully Open and Injection Occurs	33.9
LPCI Injection Valve Fully Open and Injection Starts	48.0
ADS Valves Open	125.5

Table 3.52-2
Sequence of Events for 0.08 ft^2 Break with Battery Failure at 3917 MWt and 100% Flow

EVENT	TIME (sec)
Break Occurs	0.0
High Drywell Pressure Trip (assumed)	0.0
Recirculation Pumps Trip	0.0
Feedwater Pumps Trip	0.0
Scram Initiated(1)	0.0
Signal to Start CS	1.0
Signal to Start LPCI	1.0
Signal to Start Diesel Generator	1.0
Feedwater Flow Reaches Zero	5.0
Low-Low Water Level (L1) Trip	103.2
MSIVs Close	108.7
Turbine Admission Valve Closes	182.5
ADS Valves Open	224.2
CS IV Pressure Permissive Reached	333.3
CS Injection Valve Fully Open and CS Ready to Inject	346.3
LPCI IV Pressure Permissive Reached	353.2
LPCI Injection Valve Fully Open and LPCI Ready to Inject	378.3

3.53 Provide the reactor vessel level setpoints used for reactor scram, ADS, Core spray, HPCI and LPCI in terms of height above the core at the CPPU conditions.

Response
Except for steamline breaks outside of containment, core spray, HPCI and LPCI are initiated on high drywell pressure, which is assumed to occur at the start of the LOCA event. If there were no high drywell pressure initiation signal, core spray and LPCI would initiate on low-low-low water (L1) level at 378.5 inches above vessel zero and HPCI would initiate on low-low water (L2) level at 469.5 inches above vessel zero. The low-level scram (L3) level is at 535.0 inches above vessel zero. ADS initiates on L1 (378.5" AVZ) concurrent with high drywell pressure. Top of active fuel is 366.3 inches above vessel zero. The L1 and L2 levels are analytical limits for the LOCA analysis and are not nominal instrument setpoints.

3.54 NEDC-33172 provides the results of LOCA analyses for Hope Creek at the uprate power level for a mixed core of GE14 and SVEA-96+ fuel. Please justify

(1) The initial water level is assumed to be at the low water scram (L3) level.

that the fuel burnup and power peaking assumed in these analyses for both fuel types bound those which will be experienced for cycle [15] of Hope Creek.

Response
The exposure effects for LOCA events generally depend on the gap conductance and the PLHGR. Except for pellet restructuring early in pin life, the gap conductance decreases with increasing exposure due to fission gas buildup. [[

]] The SVEA fuel was analyzed for Hope Creek over the entire range of exposures that defined the LHGR curve. [[

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3.55 Provide a table of steady state initial conditions at the CPPU conditions. The table should include reactor power, reactor pressure, water level in the RPV, total core mass flow, feedwater flow, steam flow, recirculation flow rates, core inlet temperatures, etc.

Response
The requested information is provided in Table 3.55-1 for the operating conditions used in the analyses of the limiting large and small breaks. Since the small break analysis uses an initial water level at the scram level, the initial bulkwater level at rated flow in Table 3.55-1 is based on the scram level rather than the normal water level. The bulkwater level is the level inside of the shroud and is lower than the sensed water level because of the dryer pressure drop. Table 3.55-1 includes the feedwater and CRD flows as used in the heat balance, but the SAFER analysis assumes the CRD flow is zero.

Table 3.55-1
Plant Operational Parameters

Operational Parameters	Units	EPU At Rated Flow (Small Break) Appendix K	EPU At MELLLA Flow (DBA Break) Appendix K
Core thermal power	MWt	3917	3917
Vessel steam dome pressure	psia	1055	1055
Vessel steam output	Mlbm/hr	17.20	17.19
Core flow	Mlbm/hr	100	94.8
Recirculation drive flow-Loop A	Mlbm/hr	17.1	16.2
Recirculation drive flow-Loop B	Mlbm/hr	17.1	16.2
Feedwater flow	Mlbm/hr	17.17	17.16
CRD flow	lb/hr	32000	32000
Feedwater temperature	°F	434.1	434.0
Core inlet inlet enthalpy	BTU/lbm	529.4	528.0
Initial bulkwater level	Inches above vessel zero	519.7	546.5

3.56 Question Deleted.

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), March 2, 2007