Exelon Generation.

PROPRIETARY INFORMATION – WITHHOLD UNDER 10 CFR 2.390

10 CFR 50.90
10 CFR 2.390

July 31, 2013

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

Peach Bottom Atomic Power Station, Units 2 and 3
Facility Operating License Nos. DPR-44 and DPR-56
NRC Docket Nos. 50-277 and 50-278

Subject: Extended Power Uprate License Amendment Request – Supplement 7
Response to Request for Additional Information - Extended Power Uprate

Reference:
1. Exelon letter to the NRC, "License Amendment Request - Extended Power Uprate," dated September 28, 2012 (ADAMS Accession No. ML122860201)
2. NRC letter to Exelon, "Request for Additional Information Regarding License Amendment Request for Extended Power Uprate (TAC Nos. ME9631 AND ME9632)," dated July 1, 2013 (ADAMS Accession No. ML13178A331)

In accordance with 10 CFR 50.90, Exelon Generation Company, LLC (EGC) requested amendments to Facility Operating License Nos. DPR-44 and DPR-56 for Peach Bottom Atomic Power Station (PBAPS) Units 2 and 3, respectively (Reference 1). Specifically, the proposed changes would revise the Renewed Operating Licenses to implement an increase in rated thermal power from 3514 megawatts thermal (MWt) to 3951 MWt. During their technical review of the application, the NRC Staff identified the need for additional information. Reference 2 provided the Request for Additional Information (RAI).

This letter addresses a request from the staff of the Containment and Ventilation Branch (SCVB) of the U. S. Nuclear Regulatory Commission to provide information in support of the request for amendment for the extended power uprate. During a conference call between the NRC staff and EGC conducted on June 27, 2013, it was agreed that EGC would provide a response to all of the RAI questions (except SCVB-RAI-25) within 30 days of the date of the letter transmitting the SCVB RAI questions (Reference 2). The response to RAI-25 would be provided within 60 days of the date of the letter. In addition, during a conference call between Mr. Borton of EGC and Mr. Ennis of the NRC conducted on July 15, 2013, it was agreed that EGC would provide a response to

Attachment 1 contains Proprietary Information.
When separated from Attachment 1, this document is decontrolled.

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question SCVB RAI-21 in a separate letter. Responses to both SCVB RAI-21 and SCVB RAI-25 will be submitted by August 30, 2013.

GE Hitachi Nuclear Energy America (GEH) considers portions of the information provided in the attached response to be proprietary and therefore exempt from public disclosure pursuant to 10 CFR 2.390. The proprietary information in Attachment 1 is clearly identified. A non-proprietary version of this information is provided in Attachment 2. In accordance with 10 CFR 2.390, EGC requests Attachment 1 be withheld from public disclosure. An affidavit supporting this request for withholding is included as Attachment 3.

EGC has reviewed the information supporting a finding of no significant hazards consideration and the environmental consideration provided to the U. S. Nuclear Regulatory Commission in Reference 1. The supplemental information provided in this submittal does not affect the bases for concluding that the proposed license amendment does not involve a significant hazards consideration. Further, the additional information provided in this submittal does not affect the bases for concluding that neither an environmental impact statement nor an environmental assessment needs to be prepared in connection with the proposed amendment.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), EGC is notifying the Commonwealth of Pennsylvania and the State of Maryland of this application by transmitting a copy of this letter along with the non-proprietary attachments to the designated State Officials.

There are no regulatory commitments contained in this letter.

Should you have any questions concerning this letter, please contact Mr. David Neff at (610) 765-5631.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 31st day of July, 2013.

Respectfully,

Kevin F. Borton
Manager, Licensing – Power Uprate
Exelon Generation Company, LLC

Attachments:
1. Response to Request for Additional Information – SCVB - Proprietary
2. Response to Request for Additional Information – SCVB - Non-Proprietary
3. Affidavit in Support of Request to Withhold Information

cc:	USNRC Region I, Regional Administrator	w/attachments
	USNRC Senior Resident Inspector, PBAPS	w/attachments
	USNRC Project Manager, PBAPS	w/attachments
	R. R. Janati, Commonwealth of Pennsylvania	w/o proprietary attachments
	S. T. Gray, State of Maryland	w/o proprietary attachments

Attachment 2

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

Response to Request for Additional Information – SCVB

Response to Request for Additional Information

Containment and Ventilation Branch

By letter dated September 28, 2012, Exelon Generation Company, LLC (Exelon) submitted a license amendment request for Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3. The proposed amendment would authorize an increase in the maximum power level from 3514 megawatts thermal (MWt) to 3951 MWt. The requested change, referred to as an extended power uprate (EPU), represents an increase of approximately 12.4 percent above the current licensed thermal power level.

The NRC staff has reviewed the information supporting the proposed amendment and by letter dated July 1, 2013 (NRC Accession No. ML13178A331) has requested information to clarify the submittal. The response to that request, except for RAIs 21 and 25, is provided below. A response to RAIs 21 and 25 will be provided by August 30, 2013.

SCVB- RAI-1

For the parameters shown in the table below [table included in response], please provide the current analysis input values and the EPU analysis input values used for the short-term double-ended guillotine Recirculation Loop Suction Line Break (RSLB) Design-Basis Loss-of-Coolant Accident (DBLOCA) containment pressure response analysis which resulted in a drywell peak pressure of 50.4 pounds per square inch (psig) (under EPU conditions) as shown in Table 2.6-1 of the Power Uprate Safety Analysis Report (PUSAR[2]). Provide justification for the differences between the current and the EPU analysis input value if the EPU value is less conservative. Also justify that the EPU value used for the analysis remains conservative for the peak drywell pressure response.

RESPONSE

The requested parameter input values for the referenced analysis are provided in the Table below. Where the EPU value is less conservative, justification for the differences between the current and the EPU analysis input value and justification that the EPU value used for the analysis remains conservative for the peak drywell pressure response is provided. The justification column is indicated as "N/A" if there is no change between the current and EPU value or if the EPU value remains conservative with respect to the peak drywell pressure response.

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[2] A proprietary (i.e., non-publicly available) version of the PUSAR is contained in Attachment 6 to the application dated September 28, 2012. A non-proprietary (i.e., publicly available) version of the PUSAR is contained in Attachment 4 to the application dated September 28, 2012.

Parameter	Current analysis input value	EPU analysis input value	Justification for differences between current and EPU analysis input value if the EPU value is less conservative
RSLB critical flow model	[[		N/A
Break flow area		]]	N/A
Decay heat model	1971 ANS 5 + 20%	1971 ANS 5 + 20%	N/A
Percentage of initial reactor thermal power	102%	102%	N/A
Initial reactor pressure	1053 psia	1068 psia	[[ ]]
Initial containment pressure	2.5 psig	2.5 psig	N/A
Initial containment temperature	145°F Drywell 95°F Wetwell	70°F Drywell 95°F Wetwell	[[ ]]
Initial containment relative humidity	100% Wetwell 20% Drywell	100% Wetwell 20% Drywell	N/A
Initial suppression pool level	High Water Level	High Water Level	N/A
Initial suppression pool temperature	95°F	95°F	N/A
Initial downcomer submergence height	4.4 ft	4.4 ft	N/A
Downcomer pressure loss coefficient	5.17 (non-dimensional units)	5.17 (non-dimensional units)	N/A
Drywell holdup volume	N/A	N/A	[[ ]]
Time from scram at which Main Steam Isolation Valve (MSIV) starts to close	0.5 seconds	0.5 seconds	N/A
MSIV closure time	3 seconds	3 seconds	N/A

Parameter	Current analysis input value	EPU analysis input value	Justification for differences between current and EPU analysis input value if the EPU value is less conservative
Time from scram at which Feedwater (FW) isolation valve starts to close	[[	]]	N/A
FW valve closure time	[[	]]	N/A
FW temperature	387°F [[ ]]	384°F [[ ]]	[[ ]]
Drywell free volume	175,800 ft³	175,800 ft³	N/A
Wetwell free gas space volume	127,700 ft³	127,700 ft³	N/A
Initial suppression pool volume	127,300 ft³	127,300 ft³	N/A
Initial suppression pool height	14.9 ft	14.9 ft	N/A
Total core spray flow to reactor	N/A Note 1	N/A Note 1	N/A
Time of core spray initiation from reactor scram	N/A Note 1	N/A Note 1	N/A
Total Low Pressure Coolant Injection (LPCI) flow to reactor	N/A Note 1	N/A Note 1	N/A
Time of LPCI initiation from reactor scram	N/A Note 1	N/A Note 1	N/A

Note 1: [[
]]

SCVB-RAI-2

For the parameters shown in the table below [table included in response], please provide the current analysis input values and the EPU analysis input values used for the long-term Small Steam Line Break (SSLB) LOCA analysis that resulted in the most limiting peak suppression pool temperature of 187.6 °F for the Net Positive Suction Head (NPSH) analysis, and a peak drywell temperature of 340 °F for the drywell equipment environment qualification (EQ), as shown in Table 2.6-1 of the PUSAR. Provide justification for the differences between the current and the EPU analysis input value if the EPU value is less conservative. Also justify that the EPU values used for the analysis remain conservative for the peak drywell and suppression pool temperatures.

RESPONSE

The requested parameter input values for the referenced analysis are provided in the Table below. Where the EPU value is less conservative, justification for the differences between the current and the EPU analysis input value and justification that the EPU value used for the analysis remains conservative for the peak drywell and suppression pool temperature response is provided. The justification column is indicated as "N/A" if there is no change between the current and EPU value or if the EPU value remains conservative for the peak drywell and suppression pool temperatures.

Parameter	Current analysis input value	EPU analysis input value	Justification for differences between current and EPU analysis input value if EPU value is less conservative
SSLB critical flow model	[[		N/A
Break flow area		]]	N/A
Decay heat model	ANS 5.1-1979 + 2σ	ANS 5.1-1979 + 2σ	N/A
Percentage of initial reactor thermal power	102%	102%	N/A
Initial containment pressure	2.5psig	2.5psig	N/A
Initial containment temperature	[[	......................]]	[[ ]] N/A – Limiting Pool Temperature analysis
Initial containment relative humidity	20% Drywell 100% Wetwell	20% Drywell 100% Wetwell	N/A
Initial suppression pool level	Low Water Level	Low Water Level	N/A
Initial suppression pool temperature	95°F	95°F	N/A

Parameter	**Current analysis input value**	**EPU analysis input value**	**Justification for differences between current and EPU analysis input value if EPU value is less conservative**
Initial downcomer submergence height	4.0 ft	4.0 ft	N/A
Downcomer pressure loss coefficient	5.17 (non-dimensional units)	5.17 (non-dimensional units)	N/A
Drywell holdup volume	[[ ]]	4,416 ft^3	[[ ]]
Time from scram at which MSIV starts to close	0.5 seconds	0.5 seconds	N/A
MSIV closure time	3 seconds	3 seconds	N/A
Time from scram at which FW valve starts to close	[[	Note 1	[[
FW valve closure time	]]	[[ ]] Note 1	]]
FW temperature	383.2°F	384°F	N/A - higher FW temperature is conservative
Drywell free volume	175,800 ft^3	175,800 ft^3	N/A
Wetwell free gas space volume	132,000 ft^3	132,000 ft^3	N/A
Initial suppression pool volume	122,900 ft^3	122,900 ft^3	N/A
Initial suppression pool height	14.5 ft	14.5 ft	N/A
Residual Heat Removal (RHR) heat exchanger K-value	270 BTU/s-°F	305/500 BTU/s-°F Note 2	This is the new design basis RHR Heat Exchanger K-factor in support of CAP credit elimination. Refer to the response to SCVB RAI-7.

Parameter	**Current analysis input value**	**EPU analysis input value**	**Justification for differences between current and EPU analysis input value if EPU value is less conservative**
RHR operating mode (spray or pool cooling)	Spray Mode Note 7	Note 3	[[ ]]
RHR heat exchanger hot side flow	9,500 gpm	8,600 gpm Note 4	The stated EPU flow rate is the revised PBAPS design basis flow rate.
RHR heat exchanger cold side flow	4500 gpm Note 5	4500 gpm Note 5	N/A
Total core spray flow to reactor	6250 gpm	6250 gpm	N/A
Total High Pressure Coolant Injection (HPCI) flow to the reactor	[[		]]
Thermal conductor shape (for example wall, hollow cylinder, or rod)	Note 6	Note 6	These changes are due to re-validation of existing conditions.

Parameter	**Current analysis input value**	**EPU analysis input value**	**Justification for differences between current and EPU analysis input value if EPU value is less conservative**
Thermal conductor material of each shape	Note 6	Note 6	These changes are due to re-validation of existing conditions.
Thermal conductor heat transfer area of each shape	Note 6	Note 6	These changes are due to re-validation of existing conditions.
Thermal conductor heat transfer coefficient for each shape	Note 6	Note 6	These changes are due to re-validation of existing conditions.

Note 1: [[

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Note 2: [[

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Note 3: [[

]]

Note 4: [[

]]

Note 5: [[

]]

Note 6: [[

]]

Current Analysis

Drywell Heat Sink Parameter	Node 1	Node 2	Node 3	Node 4	Node 5[(a)]
[[					
					]]

Wetwell Airspace Heat Sink Parameter	Node 1	Node 2[(a)]
[[		
		]]

Suppression Pool Heat Sink Parameter	Node 1
[[	
	]]

Note 6 (continued)

EPU Analysis

Drywell Heat Sink Parameter	Node 1	Node 2	Node 3	Node 4	Node 5[a]
[[					
					]]

Wetwell Airspace Heat Sink Parameter	Node 1
[[	
	]]

Suppression Pool Heat Sink Parameter	Node 1
[[	
	]]

(b) [[

]]

Note 7: [[

]]

SCVB-RAI-3

Section 2.6.1 of the PUSAR states all the assumptions used to maximize the drywell pressure response in the short-term analysis. Explain the basis for the assumed vent system pressure loss coefficient used in the analysis to maximize the peak drywell pressure during the initial blowdown period.

RESPONSE

Plant specific vent system pressure loss coefficients were developed during the Mark I containment long term program (Reference 3-1) and validated in an Electric Power Research Institute Report (EPRI) 1/12 scale model test documented in 1978 (Reference 3-2). The PBAPS plant specific value is 5.17 as documented in PUSAR Table 2.6-2, Item 2.F. This value is used for both the PBAPS Current Licensing Basis (CLB) and EPU containment analyses.

References

3-1 GE Nuclear Energy, "Mark I Containment Load Definition Report (LDR)," NEDO-21888, Revision 2, November 1981.

3-2 Electric Power Research Institute Report, "Three-Dimensional Pool Swell Modeling of a Mark I Suppression System," EPRI NP-906, October 1978.

SCVB-RAI-4

Section 2.6(a) of General Electric Licensing Topical Report NEDC-32424P-A, "Generic Guidelines for General Electric BWR Extended Power Uprate," dated February 1999, (ADAMS Accession No. ML003680231) states:

> The [Super Hex] SHEX computer code for the calculation of suppression pool response to LOCA events has been approved (Reference 7) on a plant-specific basis, provided that confirmatory calculations for validation of the results were included in the plant-specific request.

Please describe how the plant-specific benchmark confirmatory calculation results, validating the use of the SHEX code, was addressed for the PBAPS long-term containment analysis.

RESPONSE

PBAPS uses the Mark I containment design. Per the discussion in Section 4.1 of the NRC Safety Evaluation (SE) for NEDC-33004P (Reference 4-1), benchmarking cases, originally stipulated in References 4-2 and 4-3, using SHEX are not required for Mark I and Mark III containment analyses. As noted in the SE: "The NRC has performed independent confirmatory analyses on extended uprates for both Mark I and Mark III containment designs and found the results consistent with SHEX results. Therefore, the confirmatory calculations with SHEX (benchmarking with current licensing basis assumptions – pre-uprate) for plant specific modeling are not required for extended power uprates for Mark I and Mark III containment designs."

Therefore, following the USNRC SE of Reference 4-1, confirmatory benchmarking cases of SHEX are not required and were not performed for the PBAPS EPU.

References

4-1 GE Nuclear Energy, "Constant Pressure Power Uprate," NEDC-33004P-A, Revision 4, Class III (Proprietary), July 2003; and NEDO-33004, July 2003.

4-2 Office of Nuclear Reactor Regulation Position Concerning the General Electric Boiling-Water Reactor Extended Power Uprate Program NEDC-32424P, Generic Guidelines for General Electric Boiling-Water Reactor Extended Power Uprate (TAC No. M91680), February 8, 1996.

4-3 Letter to Gary L. Sozzi (GE) from Ashok Thadani (NRC) on the Use of the SHEX Computer Program and ANSI/ANS 5.1-1979 Decay Heat Source Term for Containment Long-Term Pressure and Temperature Analysis, July 13, 1993.

SCVB-RAI-5

Table 2.6-1 of the PUSAR shows that the Design case (D) peak drywell pressure of 50.4 psig is greater than the Bounding case (B) peak drywell pressure of 48.7 psig. As per footnote 7 of Table 2.6-1, the Design case assumes an initial containment pressure of 2.5 psig and an initial drywell temperature of 70 °F. The Bounding case assumes an initial containment pressure of 2.0 psig and an initial drywell temperature of 125 °F. This implies that a conservative drywell pressure response analysis uses a maximum Technical Specification (TS) initial drywell pressure, and a minimum possible drywell temperature.

a) Please provide and justify the values of initial drywell pressure, initial drywell temperature and relative humidity for conservative calculation of the peak drywell pressure 'Pa' for 10 CFR Part 50 Appendix J leak rate testing.

b) What is the most conservative value of Pa?

RESPONSE

As an introduction to this RAI response, EGC is clarifying the purpose of performing the PBAPS EPU containment analysis at both the "Design Case" and "Bounding Case" initial conditions of drywell temperature and pressure. The use of the "Design Case" initial drywell temperature and pressure was to provide the most conservative hypothesized initial conditions in order to demonstrate that a DBLOCA initiated at the PBAPS EPU power level would not challenge the PBAPS containment design pressure of 56 psig. The use of the "Bounding Case" initial drywell temperature and pressure was to provide conservative initial conditions in order to determine a conservative containment pressure response due to a DBLOCA at the PBAPS EPU power level. The containment pressure response determined from the DBLOCA using the "Bounding Case" initial conditions was then used to determine a conservative value of 'Pa' for 10 CFR Part 50 Appendix J leak rate testing.

b) The peak containment pressure result for the Bounding Case analysis, 48.7 psig, is below the current "Pa" value of 49.1 psig stated in PBAPS Technical Specification 5.5.12, and EGC is not requesting a modification to this 49.1 psig value for the PBAPS EPU LAR. Peak drywell pressures reported in Table 2.6-1 of PUSAR are from containment short term DBA LOCA analysis. [[

]] As stated in the RAI, the results from two initial drywell conditions (Design case and Bounding case) are reported. The following major parameters are used:

- Initial Drywell Pressure: [[

  ]]
- Initial Drywell Temperature: [[

  ]]
- Initial Drywell Humidity: Assumed value is 20% relative humidity. [[

  ]] This value is unchanged from the PBAPS current licensing basis analysis of record. This value is the minimum value for the plant normal operation.

The use of the Design Case initial drywell temperature, pressure and relative humidity was to provide the most conservative hypothesized initial conditions in order to demonstrate that a DBA LOCA initiated at the PBAPS EPU power level would not challenge the PBAPS containment design pressure of 56 psig. The Design Case initial temperature of 70°F is well below the lowest drywell initial temperature that can be achieved with PBAPS operating at power and was therefore very conservative for demonstrating the maximum PBAPS containment pressure response at EPU conditions.

The initial drywell temperature, pressure and relative humidity for the Bounding Case were developed with a conservative historical statistical basis, which also achieve a conservative prediction of the containment pressure response due to a DBA LOCA at the PBAPS EPU power level. The containment pressure response determined from the DBA LOCA using conservative initial conditions was then used to determine a conservative value of 'Pa' for 10 CFR Part 50 Appendix J leak rate testing. The Bounding Case initial temperature of 125°F represents the lower statistical bound (2-sigma uncertainty) of the 5-year historical normal drywell operating temperature during power operation of the PBAPS units. The 2 psig value is intended to represent the maximum normal operating drywell pressure that could occur at PBAPS. The immediate operator action upon reaching this 2 psig value, should the drywell pressure actually reach 2 psig during normal operation, is to manually scram the reactor.

b) Per 10 CFR Part 50 Appendix J, "Pa" is defined as the calculated peak containment internal pressure as related to the Design Basis Accident. The current and proposed 'Pa' value for PBAPS EPU shown in PBAPS TS 5.5.12 (49.1 psig) bounds the PBAPS EPU containment peak pressure of 48.7 psig determined from a DBA LOCA containment analysis using conservative input assumptions.

SCVB-RAI-6

As discussed in PUSAR Section 2.6.3.1.1, the calculated peak drywell wall temperature of 281 °F is the same as the design temperature. Please explain the method of calculating the wall temperature based on the peak drywell gas temperature of 340 °F, including the assumptions used for conservative results. What is the limiting drywell wall temperature obtained from dual unit interaction analysis? In case it has the same value (i.e., 281 °F) as obtained from the single unit analysis, please justify why it is the same.

RESPONSE

Predicted peak drywell (DW) shell temperatures reported in PUSAR Section 2.6.3.1.1 (Reference 6-1) are obtained from steam line break analysis with the [[

]] This results in the peak DW wall temperature of 281°F for both the single unit and dual unit interaction analyses.

The maximum predicted DW shell temperatures occur at the beginning of the event prior to the initiation of DW sprays. This is because the maximum DW atmosphere temperature and DW pressure conditions occur during this early period with maximum heat transfer to the DW shell. Postulated interruptions which may occur in DW spray operation due to "dual unit interaction" would produce temporary increases in DW atmosphere temperature and pressure and consequently DW shell temperature. However, these interruptions attributed to "dual unit interaction" occur later in the event, when the non-accident unit has depressurized below the 450 psig reactor pressure vessel (RPV) pressure required for the generation of a LOCA signal from the non-accident unit.

Figure 6-1 below illustrates the impact of multiple containment cooling (DW spray) interruptions on the accident unit DW temperature response. Note that Figure 6-1 is an annotated copy of PUSAR Figure 2.6-10. While Figure 6-1 is for the DW airspace temperature, the DW shell temperature response will follow the same trend as illustrated in Figure 6-1.

The maximum DW airspace and DW shell temperature occurs early in the event with the assumption that a High DW pressure/Low RPV pressure LOCA signal occurs in the accident unit 10 minutes after the accident initiation. This LOCA signal at 10-minutes will result in a further 10 minute delay in the initiation of DW spray in the accident unit (20 minute total delay for DW spray initiation). A subsequent interruption of DW spray on the accident unit due to "dual unit interaction" occurs much later in the event when the accident unit has depressurized, which results in a lower energy release and subsequent lower reheat of the DW atmosphere and DW shell.

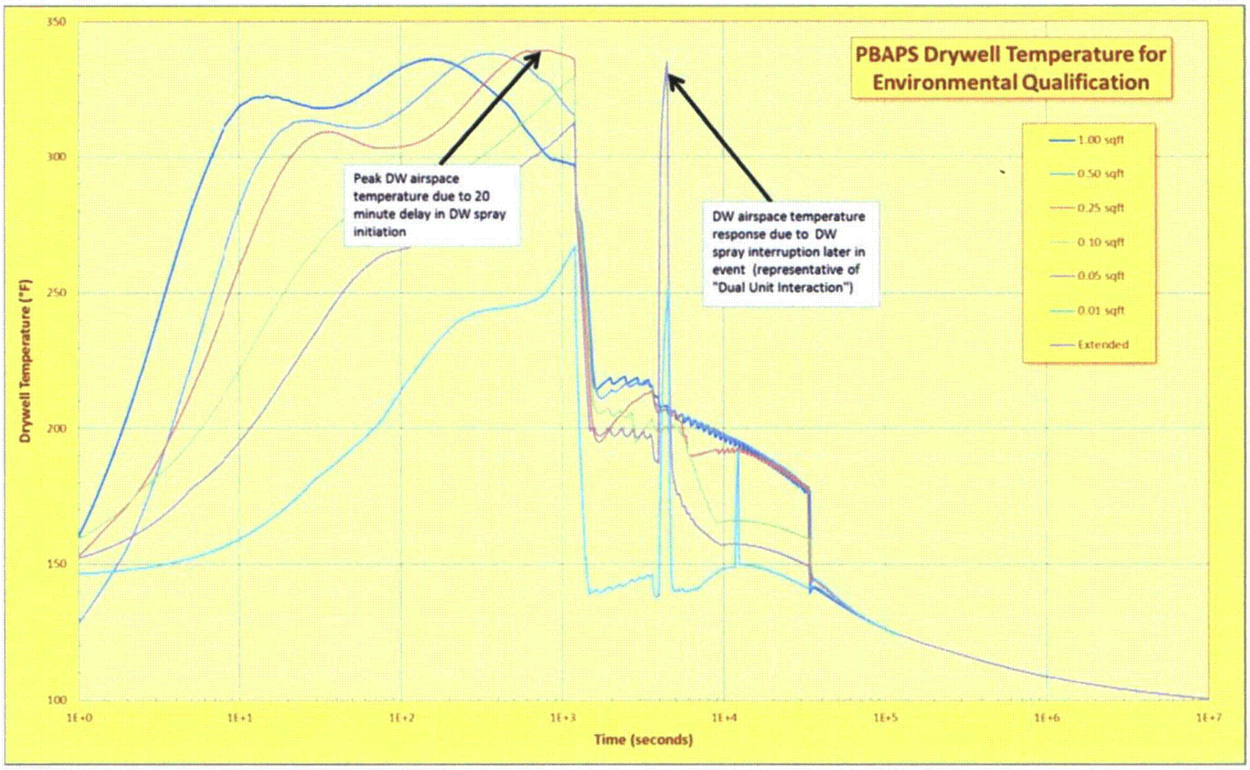

Figure 6-1 - PBAPS EPU DW Temperature Response

SCVB-RAI-7

In Section 2.6.5.1 of the PUSAR, the second sentence on page 2-272 states:

> The performance testing acceptance criteria will be revised based on the EPU analyses to reflect the minimum acceptable heat removal capability that is greater than the value assumed in the analyses.

a) Please describe the testing frequency, the current and EPU acceptance criteria for the RHR heat exchanger performance testing, and explain the basis of the EPU acceptance criteria.

b) Describe if there are different required RHR heat exchanger performance values (K values) for different events.

c) Please confirm that the heat exchanger heat removal rate acceptance criteria bounds the required heat removal capacity for the most limiting event in item (b) above.

d) Describe the Generic Letter (GL) 89-13 testing for the RHR heat exchangers and discuss the accuracy of the testing with respect to design conditions. With a lower heat transfer margin for the RHR heat exchangers, please justify your reliance of GL 89-13 testing as a means of assuring that the required heat transfer capability of the RHR heat exchangers is maintained.

RESPONSE

a) Each of the four RHR heat exchangers (per unit) is tested once every four years. Both current and EPU acceptance criteria are based on the heat exchanger (HX) performance assumed in the respective design basis analyses. The current acceptance criterion is based on a single RHR HX K-value of 270 BTU/sec-°F. The EPU acceptance criterion will be based on a single RHR HX K-value of 305 BTU/sec-°F.

b) The same HX performance (fouling resistance) corresponding to a single RHR HX K-value of 305 BTU/sec-°F at 8600 gpm RHR flow rate and 4500 gpm High Pressure Service Water (HPSW) flow rate was used in all analyses such that there is no substantive difference in the HX condition (fouling resistance) from one event to the other.

c) EGC confirms that the heat exchanger performance acceptance criterion reflects the required heat removal capacity for the most limiting event.

d) The GL 89-13 testing of the RHR HXs involves installation of temporary temperature and permanent flow instrumentation to collect data necessary to compute HX shell side and tube side heat transfer rates. With respect to the design conditions (acceptance criteria) the implementing test procedures include steps to compare the process and tube side heat transfer rates and to statistically evaluate test data such that the results conservatively account for the uncertainties of each test. Thus, the accuracy of each test, which can vary from one test to another, is reflected in the test result which is compared to the acceptance criteria.

As stated in the response to SCVB RAI-7.a) above, the EPU acceptance criteria basis K-value is 305 BTU/sec-°F. Historical test data shows that the maximum RHR HX fouling from recent tests (2008-2012) resulted in a minimum K-value of approximately 330 BTU/sec-°F (including test measurement uncertainty, explained above). This margin remains sufficiently large such that the EPU acceptance criterion is not expected to be challenged during future plant operation. Additionally, current heat exchanger maintenance (cleaning) frequencies are not expected to be changed or adversely impacted. The PBAPS GL 89-13 testing program and implementing procedures will ensure that the required heat transfer capability will be maintained.

SCVB-RAI-8

With respect to Section 2.6.5.1 of the PUSAR, under the heading "Pool Temperature Response - RSLB DBLOCA:"

a) Please explain the reasons for assuming interruption of containment cooling for 10 minutes in the accident unit due to dual unit interaction when the accident unit suppression pool temperature is 10 °F below its peak reached if there was no interruption in its containment cooling.

b) What is a realistic expected containment cooling interruption time during a RSLB DBLOCA scenario compared to the 10-minute assumption used in the analysis?

RESPONSE

Background:

Section 2.6.5.1 of the PUSAR describes how both units interact and the design considerations which protect the emergency diesel generators (EDGs) from overloading during a DBA LOCA, Loss of RHR Normal Shutdown Cooling and SSLB on the accident unit. This interaction also occurs for other DBAs and Special Events such as Station Blackout (SBO) and an Appendix R fire where a loss of offsite power (LOOP) is assumed as part of the initiating event. The sequence of events in the second, non-accident unit is essentially the same for all accidents/events occurring in the first, accident unit.

The event in the non-accident unit is a LOOP followed by reactor scram and reactor pressure vessel (RPV) isolation and includes the single active failure of loss of one EDG.

The analysis assumes HPCI is the source for high pressure makeup and one loop of RHR is used for suppression pool cooling (SPC) beginning one hour after reactor scram. Since the LOOP results in the loss of drywell cooling, it is assumed that drywell pressure will rise and generate a LOCA initiation signal in less than 1 hour. The non-accident unit analysis also assumes that when suppression pool temperature reaches 110°F, but no sooner than 10 minutes after reactor scram, operators begin manual depressurization of the reactor and cooldown at 100°F/hr. This results in the non-accident reactor reaching 450 psig and generating the LOCA signal approximately 1 hour and 10 minutes after the reactor scram. This timing is assumed for evaluation of the non-accident unit suppression pool temperature response. However, the timing of the non-accident unit LOCA signal for the dual unit interaction evaluations was varied to provide a conservative accident unit suppression pool temperature response for each accident/event.

Existing procedural guidance instructs the operators to depressurize the non-accident reactor at a slower rate than the maximum allowed rate of 100°F/hr and to stop when reactor pressure reaches 500 psig. This provides margin to the 450 psig LOCA signal setpoint and allows the operators to wait until conditions permit to continue depressurization of the reactor and generation of the LOCA signal. The operators of both units are then able to coordinate the depressurization of the non-accident unit and the resulting generation of the dual unit interaction LOCA signal with the subsequent interruption in containment cooling on the accident unit. The existing procedural guidance instructs the operators to consider the rise in suppression pool temperature and reduction in NPSH for restart of RHR pumps on the accident unit due to the interruption in SPC. This guidance will be enhanced for EPU to instruct the operators to expect a 10°F rise in suppression pool temperature due to the interruption in SPC and to ensure adequate NPSH is maintained, considering this 10°F rise. The assumption of the dual unit interaction LOCA signal 10°F below the peak pool temperature if no interruption had occurred in SPC, provides a conservative evaluation of suppression pool temperature response considering the enhanced operator guidance. This guidance assures the suppression pool temperature remains within the bounds analyzed for the Emergency Core Cooling System (ECCS) pump NPSH.

The control of the non-accident unit is also credited to assure that the non-accident unit LOCA signal doesn't occur immediately prior to or following the LOCA signal on the accident unit, resulting in a 20 minute interruption in containment cooling on both units. This is appropriate since the DBA LOCA and other larger break scenarios result in a rapid RPV depressurization and generation of the LOCA signal before the non-accident unit is depressurized. The other smaller liquid and steam line breaks and those accidents/events without any break result in a longer and more controlled depressurization of the accident unit that allows coordination between both units to avoid sequential LOCA signals.

Response:

a) The timing of the interruption in SPC on the DBA LOCA unit was developed to provide a scenario which considers operating procedures, the control of the non-accident unit and the impact on suppression pool temperature. The specific timing of the assumed interruption of containment cooling at 10°F below what the peak suppression pool temperature would be if no interruption had occurred was selected based on the following:

1. As discussed above, the depressurization of the second (non-accident) unit can be controlled to time the interruption of SPC on the accident unit.

2. If the operators depressurize the non-accident unit at the maximum rate of 100°F/hr, the earliest the unit would reach 450 psig and generate the LOCA signal is at time 1 hour and 10 minutes which is approximately where it is assumed in the analysis.

3. The assumed timing is conservative because the impact of the interruption in SPC is more severe before the peak temperature is reached (approximately 2.9 hrs).

The assumed timing of the interruption in SPC is appropriate since operator guidance will be enhanced to anticipate a 10°F rise in torus temperature when SPC is interrupted. Operators will use the ECCS pump NPSH curves to ensure adequate NPSH is maintained given the assumed 10°F rise in torus temperature at the time of the interruption.

b) An exact time is not available, however, the assumption of 10 minutes is conservative since there are only a few actions, all actions are performed from the main control room, procedures are in place and the operators are prepared for the event.

c) Operators train on placing SPC in service including RHR system alignment and HPSW system alignment. RHR system alignment consists of starting an RHR pump and opening the two suppression pool return valves. HPSW system alignment consists of starting a HPSW pump and opening the RHR heat exchanger outlet valve. All of these operations are performed in the main control room. Licensed operators estimated that it would take approximately 5-10 minutes to restore containment cooling under these circumstances; therefore the conservative timing of 10 minutes was used for these analyses.

SCVB-RAI-9

Section 2.6.5.1 of the PUSAR, under the heading "Pool Temperature Response – RSLB DBLOCA," states in the last paragraph on page 2-274 that:

> The results of this evaluation of the second PBAPS (non-accident) unit response is applicable and bounding for small break LOCAs and other accidents/events on the other PBAPS unit because the scenario includes a bounding dual unit interaction and uses the minimum equipment available to reach cold shutdown.

Please explain why the dual unit interaction shutdown cooling analysis for the non-accident bounds the same analysis results for small break LOCAs and "other accident /events." What are the other accident/events considered for which this analysis is bounding?

RESPONSE

See the response to SCVB RAI-8 for a discussion of the second, non-accident unit analysis. As stated in that response, the sequence of events in the non-accident unit is the same regardless of which accident or event is postulated in the other (accident) unit.

All DBAs and Special events listed in PUSAR Table 2.6.5 were considered for the analysis of the second unit shutdown. Each accident/event was reviewed to determine if the RHR cross-tie modification would be available for the non-accident unit and to address the impact of the LOCA signal from the accident unit. The scenario analyzed for the non-accident unit is based on a combination of conservative assumptions from all the DBAs and special events and includes a loss of offsite power. These conservative assumptions are discussed below.

1. The second unit shutdown analysis utilizes design basis and/or Technical Specification limiting values as inputs rather than nominal values.

2. The analysis of the non-accident unit takes credit for only 1 RHR pump and 1 HPSW pump for SPC. No credit is taken for use of the RHR cross tie modification which would be available to the non-accident unit for all accidents/special events in the other unit except a DBA LOCA or SBO.

3. There is no effect of the dual unit interaction from a DBA LOCA on the accident unit since the LOCA signal is generated very early, prior to initiating SPC on the non-accident unit. This would also apply to the intermediate break and the larger small steam line break accidents. The smaller steam line breaks and other events without breaks have a LOCA signal generated later, after SPC is in service on the non-accident unit.

   Therefore, to bound all accidents/events on the non-accident unit, the analysis of the non-accident unit conservatively assumes one interruption in SPC due to the generation of a LOCA signal in the accident unit and a second interruption when the non-accident unit RPV is depressurized.

Each of the accidents/events in PUSAR Table 2.6-5 would apply one or two of the above conservative assumptions to the analysis of the second unit, but none would apply to all three. Therefore the combination of using TS inputs, a single train of RHR in SPC, coupled with two interruptions in SPC provides a bounding worst case scenario for the non-accident unit.

SCVB-RAI-10

Section 2.6.5.1 of the PUSAR, under the heading "Pool Temperature Response - Loss of RHR Normal Shutdown Cooling Function Event," states on page 2-276 that:

> Accomplishing [Alternate Shutdown Cooling] ASDC using either [Suppression Pool Cooling] SPC or [Containment Spray Cooling] CSC modes would be expected to take slightly longer to achieve cold shutdown. However, the time to achieve cold shutdown assuming [Containment Injection Cooling] CIC is significantly earlier than the acceptance limit time of 36 hours. Therefore additional analysis runs using either SPC or CSC modes were considered unnecessary.

A similar statement is made on page 2-277 which describes the dual unit interaction analysis.

Please explain why the ASDC using the SPC or CSC mode would take longer time than the CIC mode to attain cold shutdown in the single unit analysis or the dual unit interaction analysis.

RESPONSE

In the CIC mode of ASDC, flow through the RPV is larger than SPC and CSC modes (8600 gpm versus 6250 gpm). In the SPC and CSC modes of ASDC, RPV inlet temperature will be essentially equal to Suppression Pool (SP) temperature. In the CIC mode of ASDC, RPV inlet temperature will be lower than the SP temperature because the injection flow has been cooled by the RHR heat exchanger(s). Therefore, the CIC mode of operation will result in a shorter time to cool down the RPV due to the larger heat removal rate from the reactor vessel. This shorter time to cooldown the RPV in the CIC mode is applicable to both the single unit analysis and the dual unit interaction analysis.

The three modes of ASDC are described below in support of the above clarification:

- In the CIC mode, ASDC is established using one RHR pump to take suction from the suppression pool, passing the pump discharge through the RHR heat exchangers, injecting this cooled water directly into the reactor, and then returning to the SP via Safety Relief Valves (SRVs). RHR flow is 8600 gpm.

- In the SPC mode, ASDC is established using one loop of Core Spray (CS) (two pumps) to take suction from the SP, injecting into the RPV, and then returning to the SP via SRVs. RHR in the SPC mode is used to cool the SP. CS loop flow is 6250 gpm.

- In the CSC mode, ASDC is established using one loop of CS (two pumps) to take suction from the SP, injecting into the RPV, and then returning to the SP via SRVs. RHR in the DW/WW spray mode is used to cool the containment / SP. CS loop flow is 6250 gpm.

SCVB-RAI-11

Section 2.6.5.1 of the PUSAR, under the heading "Pool Temperature Response - Loss of RHR Normal Shutdown Cooling Function Event," states on the bottom of page 2-276 that:

> A second interruption of containment cooling on the Loss of [Normal Shutdown Cooling] NSDC Event unit is assumed due to dual unit interaction when the Loss of NSDC Event unit suppression pool temperature is 10 °F below the peak suppression pool temperature that would be experienced by the Loss of NSDC Event unit if there was no containment cooling interruption due to dual unit interaction.

Please describe the reasons for assuming a second interruption in the containment cooling of the Loss of NSDC Event unit.

RESPONSE

Section 2.6.5.1 of the PUSAR describes how both units interact and the design considerations which protect the EDGs for a DBA LOCA, Loss of RHR Normal Shutdown Cooling and SSLB on the accident unit. This interaction also occurs for other DBAs and Special Events such as SBO and an Appendix R fire where a loss of offsite power (LOOP) is assumed as part of the initiating event. The response to SCVB RAI 8 provides additional discussion regarding the interaction of PBAPS Units 2 and 3 and the resulting interruptions in containment cooling.

Each of the above events analyzed for EPU assume a LOOP which results in a scram, a loss of DW cooling and a subsequent increase in DW pressure above the LOCA initiation signal on both units.

The accident/event unit receives priority but both units are eventually depressurized to reach cold shutdown. When each unit is depressurized below 450 psig a LOCA signal is initiated due to high DW pressure and low RPV pressure, which results in a loss of containment cooling on both units. Each unit therefore loses containment cooling when it is depressurized and again when the other unit is depressurized.

SCVB-RAI-12

With respect to Section 2.6.5.1 of the PUSAR, under the heading "Pool Temperature Response - Small Steam Break LOCA:"

a) The sequence of items and operator actions assumed for the single unit analysis does not mention about the occurrence of a LOCA signal in the accident unit. Please describe the sequence including the timing of the LOCA signal assumed in the analysis.

b) The second paragraph on page 2-277 states in the last sentence that:

> For smaller steam breaks, HPCI may be available for vessel makeup, but is not credited for 10 minutes to ensure a bounding DW temperature is evaluated.

Please explain why the drywell temperature calculated is bounding by not crediting the HPCI operation for the first 10 minutes in the single unit analysis.

c) The third paragraph on page 2-277, states in the first sentence that:

> At 10 minutes, operators turn off two of the RHR pumps, and align the remaining RHR pump to provide containment cooling with a flow of 8600 gpm through one RHR heat exchanger...

Please describe at what point in time the RHR pumps start and in which operating mode of the RHR system.

RESPONSE

a) Concurrent low RPV pressure and high DW pressure that meet the conditions for a LOCA signal occur at approximately 1 hour for the limiting small break with respect to the peak SP temperature response. However, a number of cases were run to determine the most bounding case with respect to the timing of the LOCA signal. An assumed LOCA signal occurring at 3 hours and 18 minutes, which is when the SP temperature is near its peak value, results in the most conservative of all cases for the SP temperature response since containment cooling is interrupted at the worst possible time. The limiting case analysis used the bounding assumption that LOCA signal would occur at 3 hours and 18 minutes instead of 1 hour since this results in a higher peak SP temperature for the accident unit. The sequence of events is summarized in Table 12-1 below for this most limiting case.

Table 12-1
Sequence of Events for the Limiting 0.01 ft^2 Steam Line Break

Time	Event
0	Small Steam Line Break, Loss Of Offsite Power and Reactor Scram
600 seconds	Operators secure 2 RHR pumps, and align the remaining RHR pump to SPC + Wetwell Spray. HPCI injection to RPV begins.
940 seconds	Wetwell pressure reaches 9 psig. 1 RHR pump is aligned to Wetwell + Drywell Spray.
1200 seconds	Depressurization of RPV using SRVs is initiated to maintain RPV cooldown rate of 100 °F/hr.
1 hour	Cross-tie between the RHR Heat Exchangers is established, RHR flow using 1 LPCI pump is diverted through both RHR Heat Exchangers.
3 hr 18 min	Non-mechanistic LOCA signal assumed on the accident unit. Drywell and Wetwell sprays are interrupted for 10 minutes while RHR pump is realigned to Drywell + Wetwell spray.
9 hr 35 min	Initiate Automatic Depressurization System (ADS) to completely depressurize RPV and initiate Alternate Shutdown Cooling.

b) HPCI pump flow suppresses steam generation due to rapid cold water injection into the RPV and the HPCI turbine removes steam from the RPV. These two mechanisms result in RPV depressurization, hence lower drywell temperature due to less steam discharge from the break when HPCI is running. Consequently, an earlier HPCI start would result in a less severe drywell temperature response than an analysis performed with a conservatively later assumed HPCI injection timing.

c) Although there is no LOCA signal early in the SSLB event, the analysis assumed that all available ECCS pumps start with minimum delay (approximately 15 seconds) non-mechanistically. This is a conservative assumption since assumed early operation of the ECCS pumps adds more heat to the containment. Although the RHR pumps start in low pressure coolant injection (LPCI) mode, no actual LPCI injection occurs during the first 10 minutes since the RPV pressure is still higher than the pump head. At 10 minutes, 2 RHR pumps are secured. The remaining RHR pump is run in SPC mode and Wetwell Spray mode. When the Wetwell pressure reaches 9 psig, operators switch RHR from SPC mode and Wetwell Spray mode to Drywell Spray mode and Wetwell Spray mode.

SCVB-RAI-13

With respect to Section 2.6.5.1 of the PUSAR, under the heading "Pool Temperature Response - Small Steam Break LOCA:"

a) The last paragraph on page 2-278 states:

> At 10 minutes, operators turn off two of the RHR pumps and align the remaining RHR pump to provide containment cooling using with a flow of 8600 gpm through one RHR heat exchanger...

Please describe at what point in time the RHR pumps start and in which operating mode of the RHR system.

b) Please describe the sequence assumed in the non-accident unit for the dual unit interaction analysis.

c) What is the peak drywell temperature calculated in the accident unit in the dual unit interaction analysis? Provide justification in case it is bounded by the maximum peak drywell temperature 340 °F for EQ obtained from the single unit SSLB LOCA analysis.

RESPONSE

a) Although there is no LOCA signal early in the SSLB event, the analysis assumed that all available ECCS pumps start with minimum delay (approximately 15 seconds) non-mechanistically. This is a conservative assumption since assumed early operation of the ECCS pumps adds more heat to the containment. Although the RHR pumps start in LPCI mode, no actual LPCI injection occurs during the first 10 minutes since the RPV pressure is still higher than the pump head. At 10 minutes, 2 RHR pumps are secured. The remaining RHR pump is run in SPC mode and Wetwell Spray mode. When the Wetwell pressure reaches 9 psig, operators switch RHR from SPC mode and Wetwell Spray mode to Drywell Spray mode and Wetwell Spray mode.

b) The following sequence of events shown in Table 13-1 is assumed in the non-accident unit in order to maximize the SP temperature response of the accident unit.

Table 13-1
Sequence of Events for the Non-Accident Unit

Time	Event
0	Loss Of Offsite Power and Reactor Scram
600 seconds	After the Suppression Pool temperature reaches the 110 °F but no sooner than 10 minutes following initiation of the event, reactor operators initiate reactor depressurization in order to bring the non-accident unit to cold shutdown conditions within 36 hours.
1 hour	Suppression pool cooling is started with one-RHR pump and one-RHR heat exchanger in service in suppression pool cooling mode.
2 hr 25 min	Reactor pressure in the non-accident unit is reduced to 450 psig. It is assumed that drywell pressure in the non-accident unit has also exceeded the high drywell pressure setpoint by this time. 2 hours and 25 minutes is the time at which the suppression pool temperature in the accident unit would have been 10°F below its peak value if a LOCA signal were not generated in the non-accident unit

c) The peak drywell temperature of 340 °F applies to both single unit and dual unit cases. As shown in PUSAR Figure 2.6-10, the peak drywell temperature is reached at less than 1 hour 20 minutes. The latest peak occurs when there is a LOCA signal in the accident unit at approximately 1 hour 20 minutes. [[

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SCVB-RAI-14

Section 2.6.5.2 of the PUSAR, states on page 2-282 that:

> The CIC mode of ASDC results in the highest suppression pool temperature response and therefore provides a more conservative suppression pool temperature input for the NPSH evaluation of the [Core Spray] CS pump than does the SPC mode of ASDC operation.

Please note that the CIC mode of ASDC uses the RHR pump for suppression pool cooling and cooling of reactor pressure vessel (RPV) water. The above statement refers to the CS pump instead of the RHR pump. Please clarify the statement or provide justification of the use of CS pumps in the CIC mode.

RESPONSE

As stated in the question, the CS pumps are not used in the CIC mode of ASDC. The PUSAR statement intent is that the SP temperature response is higher from the CIC mode of ASDC. This higher SP temperature response (from CIC mode of ASDC) was conservatively used for the evaluation of CS NPSH should the SPC mode of ASDC (both RHR and CS pumps in operation) be used.

SCVB-RAI-15

Section 2.6.5.2 of the PUSAR, states on page 2-282 that:

> HPCI is also assumed to operate during this event, with an assumed primary water suction source from the suppression pool, to provide RPV inventory make-up with reactor pressure above the HPCI isolation pressure. The assumption of HPCI operation is conservative for the determination of peak suppression pool temperature.

Please explain why the assumption of using HPCI to provide RPV makeup is conservative for determining the peak suppression pool temperature.

RESPONSE

The assumed availability of HPCI allows implementation of a relatively slow controlled RPV cooldown rate in the analysis. If HPCI is assumed to not be available then there is no high pressure ECCS makeup to the RPV. Therefore, the analysis would need to assume operator action to initiate the ADS to depressurize the RPV so that low pressure ECCS can restore core cooling. The fast blowdown of the reactor using ADS results in an earlier transfer of vessel liquid sensible energy to the suppression pool and a faster earlier rise in the SP temperature. In turn this also produces a faster and earlier increase in the SP temperature-to-HPSW temperature difference which controls the heat removal rate of the RHR heat exchanger. This would allow more energy to be removed from the SP via the RHR heat exchanger earlier in the event and would produce a lower peak SP temperature than by normal depressurization.

SCVB-RAI-16

Section 2.6.5.2 of the PUSAR mentions various Appendix R cases (A1, A2, B1, B2, D1, D2, C1A, C2A, C1B, and C2B). Section 2.11.1.2.2 of the PUSAR mentions the four Appendix R safe shutdown methods A, B, C, and D. Please provide a description of the cases A1, A2, B1, B2, D1, D2, C1A, C2A, C1B, and C2B analyzed for NPSH and how they are related to the safe shutdown methods A, B, C, and D.

RESPONSE

PBAPS has four safe shutdown methods: A, B, C, and D as described in PUSAR Section 2.11.1.2.2. The cases A1, A2, B1, B2, C1A, C2A, C1B, C2B, D1, and D2 analyzed for NPSH are subsets of these four safe shutdown methods. These cases are described below:

Method A: Utilize the Reactor Core Isolation Cooling (RCIC) system, two SRVs and one RHR pump (in LPCI, pool cooling and alternate shutdown cooling modes) to achieve the plant shutdown. CS and HPCI are unavailable.

Case A1: Method A without stuck open safety relief valve during event.
Case A2: Method A with one stuck open relief valve during event.

Method B: Utilize the HPCI, two SRVs and one RHR pump to achieve the plant shutdown. CS and RCIC are unavailable.

Case B1: Method B without stuck open safety relief valve during event.
Case B2: Method B with one stuck open relief valve during event.

Method C: Utilize manual control of three SRVs of the ADS for depressurization of the reactor, and either: 1) one CS pump and one RHR pump in SPC mode, or 2) one RHR pump in both LPCI mode and the SPC mode. No high pressure RPV injection available (HPCI or RCIC) during event.

Case C1A: Method C without stuck open relief valve during event. Core cooling provided by 1 CS pump.
Case C2A: Method C with stuck open relief valve during event. Core cooling provide by 1 CS pump.
Case C1B: Method C without stuck open relief valve during event. Core cooling provided by 1 RHR pump in LPCI mode.
Case C2B: Method C with stuck open relief valve during event. Core cooling provided by 1 RHR pump in LPCI mode.

Method D: Utilize the HPCI, two SRVs and one RHR pump to achieve the plant shutdown. CS and RCIC are unavailable. (Same systems as Method B). However, main control room is evacuated and initiation of safety systems is performed outside of the main control room.

Case D1: Method D without stuck open safety relief valve during event.
Case D2: Method D with stuck open safety relief valve during event.

SCVB-RAI-17

With respect to Section 2.6.2 of the PUSAR, please provide a more detailed description of the Sacrificial Shield Wall (SSW) annulus pressurization and SSW plug jet impingement analysis for a Feedwater Line Break inside the annulus. List the assumptions justifying that they are conservative. Provide the analysis results and the design margin.

RESPONSE

The EPU feedwater line break (FWLB) annulus pressurization analyses were performed for both normal and off-rated conditions. The FWLB shield plug differential pressure (DP) is determined by totaling:

- The static pressurization loading in the annulus between the RPV wall and sacrificial shield wall caused by the mass flux from the broken pipe and
- The jet impingement (JI) loading on the shield plug due to high velocity jet from the pipe break. The JI load on the shield plug is caused by the break fluid emanating from the reactor vessel side of the FW nozzle safe-end based on the shield plug geometry.

The following assumptions are made in the FWLB analysis:

- The JI load calculation used a conservatively high value of 1.45 for the thrust co-efficient which bounds the results based on the Henry-Fauske model specified in ANS/ANSI 58.2 (Reference 17-1) and GSI-191 Appendix I (Reference 17-2). This conservatively results in a higher JI load.
- The Moody's subcooled critical flow model (slip) is assumed. This model that does not include friction losses is conservative since it maximizes the mass and energy release.
- An instantaneous guillotine break of the pipe is assumed. This conservatively maximizes the pressure build-up in the annulus.
- The steady state break pressure is assumed equal to the initial break pressure for both the static pressurization load and the JI load. This is conservative since the depressurization of the RPV after the break will reduce mass and energy release for the static pressurization load and will reduce the JI load.

- Initial reactor pressure for the Minimum Pump Speed (MPS) case is conservatively assumed equal to rated dome pressure. Normal operation at MPS would typically entail a reactor pressure reduction.
- Pressurization of the primary containment outside of the annulus is conservatively ignored. Pressurization of the primary containment outside of the annulus will reduce the shield plug differential pressure.

The following table provides the results of the FWLB evaluation of the shield plug. The results show that the maximum shield plug differential pressure is below the design differential pressure.

Parameter	**CLTP (AOR)**	**CLTP**	**102% EPU / Rated Core Flow**	**102% EPU / Increased Core Flow**	**MPS**	**Design Limit (psid)**
Critical Mass Flux (lbm/sec-ft^2)	8000 (Saturated)	20768.1 (Subcooled)	20716.2 (Subcooled)	20713 (Subcooled)	22257 (Subcooled)	N/A
Mass Flux of Steam in Annulus after Flashing (lbm/sec-ft^2)	2903.8	3337.2	3363.5	3365.2	2332.7	N/A
A. Annulus Pressurization Load (psid)	8.0	9.2	9.3	9.3	6.4	N/A
B. Jet Impingement Load (psid)	39.0	39.1	39.1	39.1	39.1	N/A
Maximum Shield Plug Load (psid) (Sum of A + B above)	47.0	48.3	48.4	48.4	45.5	52
Margin to Design Limit (psid)	5.0	3.7	3.6	3.6	6.5	N/A

References

17-1 American National Standards Institute/American Nuclear Society, "Design Basis for Protection of Light Water Nuclear Power Plants Against the Effects of Postulated Pipe Rupture," LaGrange, IL: American Nuclear Society, ANSI/ANS 58.2-1988, 1988 Edition.

17-2 "Confirmatory Appendices Appendix I ANSI/ANS Jet Model," NRC GSI-191 SER Appendix I, (ADAMS Accession No. ML043280009).

SCVB-RAI-18

The last paragraph under "Technical Evaluation," in Section 2.6.2 of the PUSAR states:

> With consideration of steam flashing for AP and the jet pressure (impingement on shield plug), the results of the updated conditions including the effects of the EPU and the off-rated conditions indicate that the design limit for shield plug pressure difference is not exceeded.

a) Please explain the statement: "With consideration of steam flashing for AP and the jet pressure (impingement on shield plug)..."

b) Describe the off-rated conditions.

RESPONSE

a) As described in the response to SCVB-RAI-17, the pressure loading on the shield plugs is the sum of two load components:

1) The static pressurization loading of the annulus between the reactor pressure vessel and the sacrificial shield wall, and
2) The jet impingement loading on the shield plug due to high velocity jet from the pipe break.

The water in the feedwater line is highly subcooled. Only the feedwater that flashes to steam upon the feedwater line break will cause pressurization of the annulus. This is the purpose of the statement "with consideration of steam flashing" in the PUSAR Section 2.6.2.

b) The off-rated conditions are those combinations of core thermal power and core flow that are different from the EPU rated core thermal power and the EPU rated core flow. Plant operation with reduced feedwater temperature at the rated core thermal power level is also considered an off-rated condition. Evaluation of these additional state-points on the PBAPS EPU power-flow map was performed to ensure that the entire EPU operating domain was evaluated.

The following off rated conditions were evaluated:

1) 102% EPU Rated thermal power, rated core flow – Evaluation with Final Feedwater Temperature Reduction of 90 °F.
2) 102% EPU Rated thermal power, increased core flow – Evaluation with both normal feedwater temperature and Final Feedwater Temperature Reduction of 90 °F.
3) Minimum pump speed (Point "C" of PUSAR Figure 1-1) – Evaluation performed with both normal feedwater temperature and reduced feedwater temperature.

SCVB-RAI-19

Section 2.6.1.2.2 of the PUSAR states that EPU reduces the time between subsequent safety relief valve (SRV) actuations.

a) What are the times between the first and the second actuation and between the subsequent actuations in the current analysis and the EPU analysis?

b) What is the time at which the equilibrium height is re-established after the SRV closes in the current and the EPU analysis?

c) Describe the EPU changes in the SRV logic which prevent subsequent SRV actuations until after the SRV discharge reflood level stabilizes to the equilibrium height to prevent higher SRV and SRV discharge line loads.

RESPONSE

a) The analysis does not use the timing of the first, second and subsequent SRV actuations. Instead, the analysis uses the elapsed time between the closing and the subsequent actuation as explained in the response to SCVB RAI-19.b. The bounding values for the time elapsed between the closing and the subsequent actuation were calculated as 7.25 seconds for the Current Licensed Thermal Power (CLTP) conditions and 6.6 seconds for the EPU conditions.

b) The time required for the level in the tail pipe to return to equilibrium height is not a required input for the PBAPS load case studies.

   The SRV loads for subsequent actuation are defined for PBAPS based on two limiting cases: Mark I SRV Load Case C3.1 and Load Case C.3.3 in NEDE-24555-P Rev. 2, "Mark I Containment Program Application Guide 9, Safety Relief Valve Discharge Line Reflood Transient."
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c) There are no modifications to SRV logic required for EPU since [[

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SCVB-RAI-20

Section 2.6.1.2.3 of the PUSAR states:

> The current PBAPS Mark 1 Long Term Program Plant Unique Analysis (Reference 71) determines that the maximum internal pressure and thermal loads for the torus occur during an [Intermediate Break Accident] IBA.

The above statement addresses the current analysis instead of EPU analysis. Please note that the EPU conditions could have changed as to which break (i.e., DBLOCA, IBA, or SBA) determines the maximum internal pressure and thermal loads for the torus. Please describe the impact of the DBLOCA, IBA, and SBA analyses at EPU conditions on internal pressure and thermal loads for the torus.

RESPONSE

The PBAPS Mark I Long Term Program Plan Unique Analysis Report (PUAR) (Reference 20-1), applies internal pressure and thermal loads in addition to the Mark I hydrodynamic loads. The PBAPS plant specific pressure and temperature loads were obtained from the PBAPS Plant Unique Load Definition report (PULD), also generated during the Mark I Long Term Program (Reference 20-2). The maximum PULD values for wetwell pressure (30.6 psig) and wetwell/suppression pool temperature (155°F), as reported in Reference 20-2, were generated by the PULD IBA analysis.

Results for the PBAPS DBA-LOCA, IBA, and SBA analysis performed for EPU conditions are summarized below:

Parameter	PBAPS EPU DBLOCA	PBAPS EPU IBA	PBAPS EPU SBA	Maximum PULD Value
WW pressure (psig)	26.2	25.1	20.7	30.6
Torus (WW/SP) temperature (°F)	129	137	148	155

The results of the EPU calculations demonstrate that the maximum thermal and pressure loads applied in Reference 20-1 remain bounding relative to the maximum values predicted with EPU conditions.

References

20-1 Exelon, "Peach Bottom Atomic Power Station Units 2 & 3 Mark I Long-Term Program Plant Unique Analysis Docket Numbers 50-277 and 50-278," P-1-Q-614, Revision 2, December 1985. (PBAPS PUSAR Reference 71).

20-2 GE Nuclear Energy, "Mark I Containment Program Plant Unique Load Definition Peach Bottom Atomic Power Station Units 2 & 3," NEDO-24577, Revision 2, March 1982. (PBAPS PUSAR Reference 70).

SCVB-RAI-22

Section 2.6.6 of the PUSAR, under "Technical Evaluation," states on page 2-288 that:

> Because the maximum dome pressure is also not changed for EPU, there is no effect to the ability of secondary containment to contain mass and energy released to it. There is no increase in mass and energy released to secondary containment for EPU.

a) Please explain what is meant by "ability of secondary containment to contain mass and energy released to it."

b) Which break mass and energy released in the secondary containment is being referred to in the above statement?

c) Explain how the reactor dome pressure affects the ability of the secondary containment mass and energy released to the secondary containment.

RESPONSE

a) The statement concerns the ability of the secondary containment and the Standby Gas Treatment System (SGTS) to maintain post-LOCA effluent volume within design and regulatory limits. As stated in Section 4.4 of the NRC Safety Evaluation for NEDC-33004P (Reference 22-1), the design flow capacity of the SGTS is not affected by a constant pressure power uprate because the specified primary and secondary containment leak rates are not changed by the power uprate. The PBAPS primary-to-secondary containment design leak rate of 0.7% of the primary containment volume per day is unaffected by power uprate. As such, there is no increase in the mass and energy released to the secondary containment from the primary containment due to EPU implementation.

b) The statement in SCVB RAI-22.a is in reference to a LOCA inside primary containment. The function of the SGTS is to ensure that radioactive materials that leak from the primary containment into the secondary containment following a DBA are filtered and adsorbed prior to exhausting to the environment.

c) The statement "because the maximum dome pressure is also not changed for EPU" is to re-iterate that the PBAPS EPU is a constant pressure power uprate. The design flow capacity of the SGTS is not affected by constant pressure power uprate because the specified primary and secondary containment leak rates are not changed by the power uprate. Because the design flow capacity of the SGTS is unchanged with constant pressure power uprate and because there is no increase in the primary-to-secondary containment leak rate with constant pressure power uprate, the SGTS is able to maintain the secondary containment at negative pressure and thereby contain mass and energy released to the secondary containment.

Reference

22-1 GE Nuclear Energy, "Constant Pressure Power Uprate," NEDC-33004P-A, Revision 4, Class III (Proprietary), July 2003; and NEDO-33004, July 2003.

SCVB-RAI-23

In Section 2.7.6 of the PUSAR, the Technical Evaluation states that the operating heat load in the standby diesel generator rooms will increase slightly, but is bounded by the design heat load with enough margin available to maintain design temperatures. Please describe the changes due to EPU affecting the diesel generator building heat load during normal and accident conditions.

RESPONSE

During normal conditions, EPU will have no effect on the EDG building heat loads. The dominant heat loads within the EDG building come from the diesel engine, generator, and other hot surfaces only when the EDGs are in operation. The EDGs do not operate during normal plant conditions except during EDG surveillance testing which is not changed with EPU.

For accident conditions, the total combined EDG operating load (kW) will increase with EPU. The net change in EDG loading is due to the additional HPSW pump motor load required to support the RHR cross-tie design for increased containment cooling, with some reduction in loading resulting from reduced RHR flow to support Containment Accident Pressure (CAP) credit elimination. The increase in total combined EDG operating load causes an increase in the EDG operating heat loads to the surrounding diesel generator rooms, but does not challenge the design heat loads which are the basis for the EDG building ventilation system design. Specifically, the EDG building ventilation system is sized based on a design heat load for each individual EDG room, with each EDG operating at between 3200 and 3300 kW. This bounds the maximum calculated operating EDG load for any EDG which remains below the (2000-hour) 3000 kW rating at EPU.

SCVB-RAI-24

With respect to Tables 9-2a, 9-2b, 9-2c, and 9-2d of Attachment 9 to the application dated September 28, 2012:

a) Provide the reasons for assuming that an EPU initial drywell temperature of 70 °F as opposed to 145 °F in the current licensing basis for the NPSH analysis for DBA LOCA , SSLB, loss of RHR normal shutdown cooling with loss of offsite power, and the SRV transient (Tables 9-2a, 9-2b, and 9-2c) would maximize the suppression pool temperature response. Explain why assuming an initial drywell temperature of 145 °F was conservative in the current licensing basis and why 70 °F is conservative for the EPU analysis for the suppression pool temperature response.
b) Explain the basis for choosing 70 °F for the EPU instead of any other value that would maximize the suppression pool temperature for the accidents and events listed above.

c) Provide the reasons for keeping the initial drywell temperature for EPU SBO NPSH analysis (Table 9-2d) 145 °F the same as in the current licensing basis.

RESPONSE

a) [[

]] To clarify the note in Table 9-2a of Attachment 9, a value of 70°F for initial drywell temperature was selected to maximize the containment pressure response. The SP temperatures are maximized at both EPU and CLB conditions by assuming initial SP volume, liquid temperature and RHR heat exchanger k-values, as shown in Tables 9-2a, 9-2b and 9-2c[1]. Sensitivity cases with SSLB at EPU were run with the initial drywell temperature set both to a high (145°F) and low (70°F) initial values. [[

]] Since reliance on CAP credit for PBAPS is eliminated for the EPU, assumptions to minimize containment pressure is not an analysis requirement and the only concern for the containment analysis to be used for NPSH margin evaluation, is to maximize the suppression pool temperature response.

Note [(1)]: Table 9.2c of Attachment 9 to the PBAPS EPU LAR was modified in Attachment 8 to the EGC letter to the USNRC, dated on February 15, 2013 (ADAMS Accession No. ML13051A032). The modified Table 9.2c changed the DW initial temperature to "N/A". For SRVT event, the only concern is the suppression pool temperature. [[

]] DW temperatures are not required to be modeled for the SRVT analysis.

b) As discussed in the response to Item a, [[

]] The use of the Design Case initial drywell temperature of 70°F was to provide the most conservative hypothesized initial conditions in order to demonstrate that a DBA LOCA initiated at the PBAPS EPU power level would not challenge the PBAPS containment design pressure of 56 psig. It is also used in long-term containment analyses [[ ]] the long-term containment response.

c) As discussed in the response to Item a, [[
]] Therefore it is reasonable to keep the initial drywell temperature unchanged from CLB to EPU as the suppression pool temperature is of main concern for this event with respect to evaluation of NPSH margins with credit for CAP eliminated.

SCVB-RAI-26

Note 5 in Table 2.6-1 of the PUSAR sentence states, in part, that:

> A peak bulk suppression pool temperature of 187 °F was calculated for the SSLB LOCA analysis performed for maximum drywell temperature for EQ, and is therefore the most limiting peak bulk suppression pool temperature for all LOCA break sizes.

Section 2.6.5.1 of the PUSAR under the heading "Pool Temperature Response - Small Steam Break LOCA", last paragraph on page 2-279 reports a peak suppression pool temperature of 187.6 °F, which is obtained from the SSLB LOCA dual unit interaction analysis. Please provide reasons for considering 187 °F to be the most limiting peak bulk suppression pool temperature for all LOCA break sizes instead of 187.6 °F.

RESPONSE

Note 5 in PUSAR Table 2.6-1 contains a typographical error: 187°F should read 187.6°F. The value of 187.6°F is the correct peak bulk SP temperature and was used in the NPSH evaluations.

SCVB-RAI-27

Section 2.7.3 of the PUSAR, under "Technical Evaluation" states that electrical or electronic equipment will be added in the cable spreading room due to the adjustable speed drive (ASD) modification. Please provide the final design increase in the heat load due to the planned addition of the ASDs and the impact of additional heat load on the design capacity of the control room HVAC system.

RESPONSE

PBAPS is not planning to install the ASD modification until 2015 for Unit 3 and 2016 for Unit 2 and design data is not currently available. EPU does not rely on this modification, nor is approval of this modification requested. Based on similar ASD installations at other facilities, the changes to heat loads within the Main Control Room (MCR) are expected to be negligible.

Modifications are controlled by the EGC configuration change control process that requires applicable design considerations and impacts be identified, including the impact on HVAC requirements. Thus the impact of the heat load changes on the design capacity of the Control Room Heating, Ventilating and Cooling (HVAC) system will be addressed in the final ASD modification, which will be implemented under the 10 CFR 50.59 process.

SCVB-RAI-28

In Section 2.7.5 of the PUSAR, the Technical Evaluation states that the main steam tunnel temperature increase will be less than 0.5 °F at EPU conditions. Please describe the method of evaluation of the increase in the main steam tunnel temperature at EPU conditions.

RESPONSE

The only EPU heat load increase affecting the main steam tunnel (MST) is due to the FW temperature increase. The FW temperature increase with EPU is obtained from the turbine cycle heat balances.

The methodology to predict the increase in MST area temperature due to the FW temperature increase with EPU is consistent with that used in the current PBAPS design basis calculations. The piping heat loads are proportional to the temperature difference between the hot pipes and MST area. The increase in heat load from FW piping is scaled up proportional to the increase in FW temperature with EPU.

Thus, the estimated MST area temperature change is computed based on the increase in heat load, which is determined from the increase in FW temperature with EPU, considering the fraction of total heat load contribution from FW piping.

SCVB-RAI-29

Section 2.8 of Attachment 9 to the application states that all six (three per unit) condensate pumps and motors will be upgraded. The Technical Evaluation in Section 2.7.5 of the PUSAR states that "[t]he effect of condensate pump upgrades on HVAC systems will be evaluated as part of the normal modification process." Please provide the final design increase in heat load due to the condensate pump upgrades and the impact of increased heat load on the design capacity of turbine building HVAC system.

RESPONSE

The modification to install condensate pump upgrades at PBAPS is currently in development. Although the design change is not finalized, an initial evaluation of the impact on the turbine building HVAC system has been performed.

The condensate pump upgrades will require 5,000 hp pump motors (11% larger than the current 4,500 hp motors), resulting in a proportional increase in the heat load to the room. The increase in heat load is expected to result in a room temperature increase of less than 5°F. This small increase in room temperature has been evaluated to be acceptable.

Modifications are controlled by the EGC configuration change control process that requires applicable design considerations and impacts be identified, including the impact on HVAC requirements. Thus the impact of the heat load changes on the design capacity of the Turbine Building HVAC system will be documented in the final modification. This modification will be implemented under the 10CFR50.59 process.

SCVB-RAI-30

In Section 2.7.5 of the PUSAR, the Technical Evaluation does not provide a discussion of the increased HVAC heat load due to increase in the power dependent fuel pool cooling system heat load. Please provide the impact of the increased fuel pool heat load on the reactor building HVAC heat load and its HVAC design capacity.

RESPONSE

There is no additional design heat load imposed on the Reactor Building HVAC system from the spent fuel pool (SFP) due to EPU. PUSAR section 2.5.3.1.1 states that the SFP temperature is maintained within design limits through existing administrative and procedural limitations. Although the fuel pool temperature may increase slightly under EPU conditions, this change is negligible to the HVAC. The Fuel Pool Cooling and Cleanup System (FPCCS) can maintain the fuel pool temperature within design limits. Therefore, the HVAC system will be within its design capacity.

Attachment 3

Peach Bottom Atomic Power Station Units 2 and 3

NRC Docket Nos. 50-277 and 50-278

AFFIDAVIT

Note

Attachment 1 contains proprietary information as defined by 10 CFR 2.390. GEH, as the owner of the proprietary information, has executed the enclosed affidavit, which identifies that the proprietary information has been handled and classified as proprietary, is customarily held in confidence, and has been withheld from public disclosure. The proprietary information has been faithfully reproduced in the attachment such that the affidavit remains applicable.

GE-Hitachi Nuclear Energy – Americas, LLC

AFFIDAVIT

I, James F. Harrison, state as follows:

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

(2) The information sought to be withheld is contained in Enclosure 1 of GEH letter, GEH-PBAPS-EPU-423, "Review of GEH Proprietary Information in Exelon SNPB RAI Responses" dated July 25, 2013. The GEH proprietary information in Enclosure 1, which is entitled "Review of GEH Proprietary Information in Exelon SNPB RAI Responses," is identified by a dotted underline inside double square brackets. [[This sentence is an example.{3}]] In each case, the superscript notation {3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

(3) In making this application for withholding of proprietary information of which it is the owner or licensee, GEH relies upon the exemption from disclosure set forth in the *Freedom of Information Act* ("FOIA"), 5 U.S.C. §552(b)(4), and the *Trade Secrets Act*, 18 U.S.C. §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 qualifies 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, 975 F.2d 871 (D.C. Cir. 1992), and Public Citizen Health Research Group v. FDA, 704 F.2d 1280 (D.C. Cir. 1983).

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

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

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

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

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

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

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

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

(8) The information identified in paragraph (2) above is classified as proprietary because it contains the description of GEH models, methods and processes used in the extended power uprate analyses. The development of these models, methods and processes was achieved at a significant cost to GEH.

The development of these GEH models, methods and processes is derived from the extensive experience database that constitutes a major GEH asset.

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

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

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

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

Executed on this 25th day of July 2013.

James F. Harrison
Vice President, Fuel Licensing
GE-Hitachi Nuclear Energy Americas, LLC