Exelon Nuclear
200 Exelon Way
Kennett Square, PA 19348

www.exeloncorp.com

Exelon Nuclear

10 CFR 50.90

February 25, 2010

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

Peach Bottom Atomic Power Station, Unit 2
Renewed Facility Operating License No. DPR-44
NRC Docket No. 50-277

Subject: Response to Request for Additional Information - License Amendment Request for Type A Test Extension

References:

1) Letter from P. B. Cowan (Exelon Generation Company, LLC) to U.S. Nuclear Regulatory Commission, "License Amendment Request - Type A Test Extension," dated August 28, 2009

2) Letter from J. D. Hughey (U.S. Nuclear Regulatory Commission) to C. G. Pardee (Exelon Generation Company, LLC), "Peach Bottom Atomic Power Station, Unit 2 – Request for Additional Information Regarding License Amendment Request For One-Time Five-Year Containment Type A Integrated Leak Rate Test Interval Extension (TAC NO. ME2159)," dated February 23, 2010

In the Reference 1 letter, Exelon Generation Company, LLC (EGC) requested a proposed change to modify Technical Specification (TS) 5.5.12, "Primary Containment Leakage Rate Testing Program." Specifically, the proposed change will revise TS 5.5.12 to reflect a one-time extension of the containment Type A Integrated Leak Rate Test (ILRT) from 10 to 15 years. This one-time extension will require the Type A ILRT to be performed no later than October 2015.

In the Reference 2 letter, the U.S. Nuclear Regulatory Commission requested additional information. Attachment 1 contains our response to Request for Additional Information (RAI-01). Attachment 2 contains our response to RAIs 02 through 05.

No regulatory commitments are contained in this response.

Should you have any questions concerning this letter, please contact Tom Loomis at (610) 765-5510.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 25th of February 2010.

Respectfully,

Pamela B. Cowan
Director, Licensing & Regulatory Affairs
Exelon Generation Company, LLC

Attachments: 1) Response to Request for Additional Information (RAI-01)
2) Response to NRC RAIs Related to the License Amendment Request for a Type A Integrated Leak Rate Test Interval Extension for Unit 2 (RAIs 02 through 05)

cc: USNRC Region I, Regional Administrator
USNRC Senior Resident Inspector, PBAPS
USNRC Project Manager, PBAPS
R. R. Janati, Bureau of Radiation Protection
S. T. Gray, State of Maryland

Attachment 1

Response to Request for Additional Information (RAI-01)

RAI-01 Type B and Type C Combined Leakage Rate Totals:

RAI-01.1: Provide the Type B and Type C combined leakage rate totals associated with the ILRTs performed for the 1991 refueling outage and for the refueling outages conducted from 2000 to the present.

Response:

Refueling Outage	Maximum Pathway		Minimum Pathway	
	Leakage (sccm)	% of 0.6La	Leakage (sccm)	% of 0.6La
1991	51,768	68.8	20,054	26.6
2000	61,171	81.3	20,244	26.9
2002	59,042	78.5	21,379	28.4
2004	43,644	58.0	18,937	25.2
2006	53,701	71.4	28,108	37.3
2008	59,033	56.0	20,281	19.3

Note (as also contained in Reference 1):
0.6La prior to 2008 = 75,256 sccm
0.6La after 2008 = 105,350 sccm (Alternate Source Term was implemented (Safety Evaluation Report dated September 5, 2008))
sccm = standard cubic centimeters per minute

Attachment 2

Response to NRC RAIs Related to the License Amendment Request for a Type A Integrated Leak Rate Test Interval Extension for Unit 2 (RAIs 02 through 05)

RM DOCUMENTATION APPROVAL FORM

RM DOCUMENTATION NO.	PB-LAR-06	REV: 1	PAGE NO. 1

STATION: Peach Bottom Atomic Power Station

UNIT(s) AFFECTED: 2

TITLE: Response to NRC RAIs Related to the License Amendment Request for a Type A Integrated Leak Rate Test Interval Extension for Unit 2

SUMMARY:
This document contains responses to the PRA related RAIs obtained from the NRC for the PBAPS Unit 2 LAR for a one-time extension to the containment Type A integrated leak rate test (ILRT).

Revision 1 incorporates minor editorial changes.

This is a Category I RM Document IAW ER-AA-600-1012, which requires independent review and approval.

[ ] Review required after periodic Update

[X] **Internal RM Documentation** [ ] **External RM Documentation**

Electronic Calculation Data Files: N/A

Method of Review: [X] Detailed [ ] Alternate [ ] Review of External Document

This RM documentation supersedes: N/A **in its entirety.**

	Print	Sign	Date
Prepared by:	Donald E. Vanover	Donald E. Vanover	2/24/10
Reviewed by:	Robert J. Wolfgang	Robert J. Wolfgang	2/24/10
Approved by:	Gregory A. Krueger		2/24/10

RAI-02 Containment Pressure Credit For Pump Net Positive Suction Head:

RAI-02.1: Please address the impact of the proposed ILRT test interval extension on CDF given the assumption of reliance on containment pressure for CSCS NPSHa.

(Please see Section 3.2.2 of the NRC staff Safety Evaluation issued on June 25, 2008, (ADAMS Accession Number ML081140105) for additional information related to evaluating containment over-pressure credit impact using EPRI Report 1009325, Revision 2.)

Response:

The current base Probabilistic Risk Assessment (PRA) model assumption is that containment overpressure credit is not required for the low pressure Emergency Core Cooling System (ECCS) in large Design Basis Accident (DBA) Loss-of-Coolant Accidents (LOCAs) or other scenarios. However, to address this issue for consistency with the guidance provided in the NRC SER and EPRI Report noted above, bounding analyses are provided to determine the potential impact on the CDF and Large Early Release Frequency (LERF) risk metrics for the Integrated Leak Rate Test (ILRT) extension request for Peach Bottom Atomic Power Station (PBAPS), Unit 2. Three specific scenarios are analyzed (large LOCAs, Anticipated Transient Without Scram (ATWS), and other transients).

Large LOCAs

Should a pre-existing containment failure exist coincident with a large LOCA, several mitigating factors would potentially be available before a core damage end state occurred. First, there is some likelihood that the ECCS pumps would survive for some time frame under degraded NPSH conditions. Second, there is some likelihood that the operators would be able to throttle the ECCS pump flow as necessary to maintain Net Positive Suction Head (NPSH) as directed per the Emergency Operating Procedure (EOP) flowcharts. Finally, given the unlikely situation that all ECCS injection is eventually lost, other potential mitigation measures from alternate injection systems (e.g., High Pressure Service Water (HPSW) through Residual Heat Removal (RHR) would be procedurally directed and possible to initiate from the control room if necessary given all ECCS injection is lost). In this bounding assessment, these other mitigating actions are conservatively accounted for with a total failure probability of 0.1. This is consistent with guidance in NUREG-1792 [Ref. 2-3] for use of screening values for feasible operator actions. Based on the results indicated below, a more detailed analysis will not be required.

The estimated large LOCA frequency from the PBAPS PRA model is ~2E-4/yr. This can be assumed to represent that portion of the LOCA frequency that would require containment overpressure to be able to provide successful mitigation. Note that this assumption is conservative compared to the generic large LOCA (7.0E-6/yr) and medium LOCA (1.0E-4/yr) frequencies available from NUREG/CR-6928 [Ref. 2-1]. Additionally per the EPRI guidance, it can be assumed that the EPRI Class 3b contribution would also lead to the loss of containment overpressure required to maintain NPSH requirements for ECCS. In the PBAPS ILRT extension risk assessment, the base case Class 3b contribution is 2.7E-3, which is assumed to increase by a factor of 5.0 when the ILRT interval is extended to 15 years. This postulated change in the Class 3b contribution can also be used to provide a bounding estimate on CDF and LERF given the assumption that containment overpressure credit is required to mitigate all large LOCA scenarios.

$CDF_{base} = LERF_{base} = 2E\text{-}4/yr * 2.7E\text{-}3 * 0.1 = 5.4E\text{-}8/yr$

$CDF_{15\ yr\ ILRT} = LERF_{15\ yr\ ILRT} = 2E\text{-}4/yr * 2.7E\text{-}3 * 0.1 * 5.0 = 2.7E\text{-}7/yr$

$\Delta CDF = \Delta LERF = 2.7E\text{-}7/yr - 5.4E\text{-}8/yr = 2.2E\text{-}7/yr$

ATWS

The potential contribution from ATWS scenarios can also be conservatively assessed by assuming that the pre-existing containment failure coincident with an ATWS scenario would lead to a core damage end state. In this case, this does not account for the likelihood that the ECCS pumps could survive for some time frame under degraded NPSH conditions nor does it take any credit for throttling ECCS pump flow.

The estimated total transient initiating event frequency (excluding manual shutdowns) from the PBAPS PRA model is approximately 1 event per year. The failure to scram likelihood is dominated by the mechanical scram failure probability of 2.1E-6. This value is based on the NRC sponsored research at INEEL that resulted in a reassessment of the scram failure probability (NUREG/CR-5500, Vol. III [Ref. 2-2]). The impact on CDF and LERF can be similarly assessed by utilizing the Class 3b likelihood given the assumption that containment overpressure credit is required to mitigate all ATWS scenarios.

$CDF_{base} = LERF_{base} = 1/yr * 2.1E\text{-}6 * 2.7E\text{-}3 = 5.7E\text{-}9/yr$

$CDF_{15\ yr\ ILRT} = LERF_{15\ yr\ ILRT} = 1/yr * 2.1E\text{-}6 * 2.7E\text{-}3 * 5.0 = 2.8E\text{-}8/yr$

$\Delta CDF = \Delta LERF = 2.8E\text{-}8/yr - 5.7E\text{-}9/yr = 2.2E\text{-}8/yr$

Other Transients

Other general transients, including smaller LOCAs (i.e., not large LOCAs), would allow sufficient time in which to establish suppression pool cooling such that containment overpressure (if assumed to be required to maintain NPSH in DBA LOCA scenarios) would only be required in these less demanding scenarios if suppression pool cooling were to fail. For loss of suppression pool cooling scenarios, the current PBAPS PRA model already assumes that ECCS injection is eventually lost and injection from external sources (i.e., not from the suppression pool) is required for successful mitigation. Given this, the overall success criteria in these cases would not change, but the time available to provide injection from an external source could be reduced if a pre-existing containment failure existed. For typical transients without suppression pool cooling, a plant-specific Modular Accident Analysis Program (MAAP) analysis indicates that 20 hours or more would be available prior to reaching the Primary Containment Pressure Limit (PCPL) when containment vent initiation is required per the EOPs. The current PRA model assumes that ECCS injection is lost when containment venting is initiated at the PCPL. If a pre-existing containment failure exists, it can be assumed that ECCS injection would be lost prior to reaching PCPL. That time frame is likely to be somewhere between the time that the Heat Capacity Temperature Limit (HCTL) is exceeded and when the suppression pool becomes saturated (i.e., approximately 6 or more hours based on plant-specific MAAP analysis). The potential impact on CDF and LERF can therefore be approximated by assessing the impact that this reduced time has on operators to provide successful mitigation.

The total contribution from the loss of containment heat removal scenarios for PBAPS, Unit 2 can be derived from the Class II contribution shown in Table 2-1 of Attachment 4 of the submittal. That is, the sum of the Class IIA (3.30E-7/yr), IIF (4.83E-7/yr), and IIL (1.27E-8/yr) subclasses represents the loss of containment heat removal contribution for PBAPS, Unit 2 of ~8.3E-7/yr. A review of these scenarios also indicated that loss of offsite power (LOOP) events combined with emergency diesel generator failures were not significant contributors. Given this, LOOP recovery times would not have a substantial impact on this assessment, and the potential bounding impact on CDF and LERF can be assessed by assuming that every loss of containment heat removal core damage scenario is impacted by a Human Failure Event (HFE). To provide a bounding assessment, it can be conservatively assumed that these HFEs increase by a factor of 2.0 given the reduced time available for the situations when a pre-existing containment failure exists. Although the pre-existing containment breach may lead to an earlier loss of ECCS injection, the actual available time to respond to utilize alternate forms of injection prior to reaching core damage would not substantially change. For the types of HFEs that would be involved in these scenarios, most HRA methods would predict minimal impact due to these timing changes. Therefore, the factor of 2.0 is judged to be conservative. Finally, similar to the above assessments, the likelihood of the pre-existing containment failure is based on the change in the EPRI Class 3b contribution.

$$CDF_{base} = LERF_{base} = 8.3E\text{-}7/yr * 2.7E\text{-}3 * 2.0 = 4.5E\text{-}9/yr$$

$$CDF_{15\ yr\ ILRT} = LERF_{15\ yr\ ILRT} = 8.3E\text{-}7/yr * 2.7E\text{-}3 * 2.0 * 5.0 = 2.2E\text{-}8/yr$$

$\Delta CDF = \Delta LERF = 2.2E\text{-}8/yr - 4.5E\text{-}9/yr = 1.8E\text{-}8/yr$

Although this assessment of the loss of containment heat removal scenarios is limited to the internal events impact, the bounding nature of the assessment and relatively low values obtained indicate that explicit consideration of external events is not warranted.

RAI-02.1 Conclusions

The incorporation of these bounding assessment results into the analysis would not change the conclusion. That is, the increase in LERF due to the combined internal and external events challenges from extending the PBAPS ILRT frequency from 3 per 10 years to 1 per 15 years would remain in Region II between 1E-7 to 1E-6 per reactor year ("Small Change" in risk) of the Regulatory Guide 1.174 acceptance guidelines. Additionally, based on bounding assessments, the postulated change in CDF is less than 1E-6 per reactor year, which is in the less restrictive Region III ("Very Small Change" in risk) of the Regulatory Guide 1.174 acceptance guidelines.

RAI-02.1 References

[2-1] Eide, S. A. et. al., "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants," NUREG/CR-6928, January 2007

[2-2] Eide, S.A. et. al., "Reliability Study: General Electric Reactor Protection System," 1984-1995, NUREG/CR-5500, Vol. 3, May 1999.

[2-3] Kolaczkowski, A. et. al., "Good Practices for Implementing Human Reliability Analysis," NUREG-1792, April 2005.

RAI-03 Steel Liner Corrosion Events:

RAI-03.1: Provide a more complete accounting corrosion events relevant to the Peach Bottom Unit 2 containment, and an evaluation of the impact on risk results.

Response:

Based on data searches within the INPO operating experience database, the following instances of degraded containment liners were found:

1. Braidwood Unit 2 (October 2000) - While performing visual inspection of the containment surfaces, it was discovered that the containment liner did not meet the acceptance criteria of "maximum 10% metal thickness loss" in some normally inaccessible areas below the moisture barrier. [This was a degraded condition not a failed condition and therefore would not impact the risk assessment.]

2. Brunswick Unit 1 (March 2004) - inspection of the drywell personnel access penetration sleeve identified paint blisters on the 3/8" nominal thickness of the penetration sleeve. Ultrasonic testing (UT) of the penetration sleeve identified multiple areas of corrosion. Weld repairs were required to restore areas of the sleeve to required design wall thickness. [This was a degraded condition not a failed condition and therefore would not impact the risk assessment.]

3. Beaver Valley Unit 1 (February 2006) - Upon completion of the hydro demolition of the concrete and removal of rebar from this temporary Steam Generator Replacement Project (SGRP) equipment opening, three areas of corrosion and pitting were identified on the concrete side of the steel containment liner. No through wall perforations were found. [This was a degraded condition not a failed condition and therefore would not impact the risk assessment.]

4. Turkey Point Unit 4 (November 2006) - During preparations for inspection and coatings of the Unit 4 reactor cavity sump at elevation 15'-8", a hole developed in the containment building liner when a sump pump support plate was moved. [This event is applicable to the risk assessment.]

5. North Anna Unit 1 (March 2009) - Seven corroded carbon steel leak test connections with missing 1/8" diameter pipe plugs were identified during Engineering inspection in the Recirculation Spray and Containment Sump areas. [This event was a degraded condition with potential for corrosion and not a failed condition and therefore would not impact the risk assessment.]

6. Beaver Valley Unit 1 (May 2009) - During the IWE examination of the containment liner, a paint blister was identified. The blister was investigated and a through wall hole was identified. The hole was approximately 3/8" by 1" in size. [This event is applicable to the risk assessment.]

The operating experience review indicated that two relevant additional failures have occurred since the methodology to estimate the impact of corrosion-induced leakage was established in the Calvert Cliffs analysis [Ref. 3-1] that has since been utilized in several other ILRT extension requests. The Calvert analysis utilized the information available at that time to establish a historical baseline estimate of corrosion induced liner flaws. The analysis then proceeded to estimate that corrosion induced flaw likelihood will increase due to the change in the ILRT interval to 15 years. The base case assumption was that the historical flaw rate would double every five years. Since these two additional failures occurred over a longer time period than was used in the original assessment (which accounted for two failures in 5.5 years to establish the historical liner flaw likelihood), accounting for the two failures indicated above would fall below the base case analysis for corrosion induced flaw likelihood at 15 years that was already performed by Calvert and was duplicated for the PBAPS, Unit 2 ILRT extension request in Section 4.4 of Attachment 4. Additionally, to address the uncertainty associated with such probability estimation, the sensitivity analysis that was performed

in Section 6.1 of the risk assessment for PBAPS varied the doubling time for flaw likelihood rate from once every five years to once every two years and once every ten years. The sensitivity case for doubling every two years would be indicative of industry operating experience with several noted liner failures due to corrosion (not just two that have been identified). This case resulted in an increase in LERF due to corrosion of just 1.11E-08/yr (refer to Table 6.1-1 of Attachment 4 of the PBAPS submittal). This sensitivity case is bounding for the incorporation of all relevant events identified above and as such would not change the conclusions of the analysis.

RAI-03.1 References

[3-1] Response to Request for Additional Information Concerning the License Amendment Request for a One-Time Integrated Leakage Rate Test Extension, Letter from Mr. C. H. Cruse (Calvert Cliffs Nuclear Power Plant) to NRC Document Control Desk, Docket No. 50-317, March 27, 2002.

RAI-04 PRA Technical Adequacy:

RAI-04.1: Please identify who conducted the 2004 gap analysis, and who performed the 2006 assessment of the extent to which previously-identified gaps had been addressed.

Response:

The Exelon Risk Management team was responsible for the 2004 gap analysis and the 2006 assessment of the extent to which the previously identified gaps had been addressed.

RAI-05 GAP Analysis:

RAI-05.1: Describe and justify the basis for the statement that "Pre-initiator human actions do not contribute significantly to the risk significance results for this application", given that a detailed process was not employed for identifying and screening test and maintenance pre-initiators. Discuss whether this gap includes the modeling of pre-initiator errors related to test and maintenance of containment isolation valves, and if so, how resolution of the gap would impact the risk results for this license amendment request.

Response:

To the extent that the performance of the ILRT would have revealed the unavailability of Primary Containment Isolation Valves (PCIVs), this would have been included in the baseline historical failure rate used in the risk assessment. Also, any valve misalignments or PCIVs that communicate with the containment atmosphere and are

left in an open state would be self-revealing, in that plant instrumentation and pressure sensors would indicate anomalous behavior with regard to maintaining the required pressure and inert environment.

With regard to administrative processes, configuration control of PCIVs is controlled by plant Technical Specification Section 3.6.1.3, "Primary Containment Isolation Valves," as well as procedural pre-startup checklists that are performed after every outage. Additionally, Technical Specification 3.3.6.1, "Primary Containment Isolation Instrumentation," provides requirements for channel indication operability. Therefore, the ILRT frequency is independent of other processes that maintain PCIV configuration, and increasing the duration between successive ILRTs will have no impact on valves being inadvertently left in an unknown state, and subsequently have no impact on any pre-initiating errors for PCIVs.