Exelon Nuclear
200 Exelon Way
Kennett Square, PA 19348

www.exeloncorp.com

Exelon Nuclear

10CFR54

June 10, 2002

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

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: Response to Request for Additional Information

Reference:
1) July 2, 2001 Letter from Jeffrey A. Benjamin (Exelon), to NRC Document Control Desk Regarding Application for Renewed Operating Licenses

2) May 1, 2002 Letter from Michael P. Gallagher (Exelon), to NRC Document Control Desk Regarding Response to Request for Additional Information Related to Time-Limited Aging Analyses

3) March 12, 2002 Letter from Raj K. Anand (NRC) to Michael P. Gallagher (Exelon) Regarding Appendix B Aging Management Activities

Dear Sir/Madam:

Reference letter 1) transmitted an application for renewal of the operating licenses for the Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3, including Time-Limited Aging Analyses (TLAA). Subsequently, by teleconference dated May 6, 2002, the NRC requested additional information in order to complete its review of TLAA. The subject under discussion was High Energy Line Break pipe break criteria.

At PBAPS, the recirculation system piping was replaced in 1985/86 for Unit 2 and in 1988/89 for Unit 3. The replacement was designed to ASME Section III, class 1 requirements. Updated Final Safety Analysis Report Appendix A.10.3.3 states that for the recirculation system piping, breaks have been assumed to occur at intermediate locations where the Cumulative Usage Factor (CUF) exceeds 0.1. This piping was re-analyzed in 1997 with no new break locations identified. The piping was also re-analyzed in 2001 considering extended operation with no new breaks identified. It should be noted that the analysis for extended operation used a piping life of 47 years for Unit 2 and 44 years for Unit 3 and not 60 years as would occur for original piping. The same screening criterion, 0.1 CUF, was used in all of the analyses. In addition, as identified in License Renewal Application (LRA) Table 4.3.1-1, the Reactor Pressure Vessel recirculation inlet and outlet nozzles, and the Residual Heat Removal system tee connections to the recirculation pipe are also included as monitoring locations in LRA Appendix B.4.2, "Fatigue Management Activities."

A047

The response to request for additional information (RAI) 4.2-7, which was provided by reference letter 2), provided information on reactor pressure vessel axial welds for Clinton plant with values of 2.73E-6 and 1.52E-6. This was an administrative error. The correct values for Clinton plant are 2.73E-3 and 1.52E-3. We regret any inconvenience that this may have caused.

The reference 3) letter transmitted RAI on the Susquehanna Substation Wooden Pole Inspection Activity and Torus Piping inspection Activities. Attachment 1 restates the questions for your convenience and provides our responses.

If you have any questions or require additional information, please do not hesitate to call.

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

Respectfully,

Executed on 06-10-2002 Michael P Gallagher

Michael P. Gallagher
Director, Licensing & Regulatory Affairs
Mid-Atlantic Regional Operating Group

Enclosures: Attachment 1

cc: H. J. Miller, Administrator, Region I, USNRC
A. C. McMurtray, USNRC Senior Resident Inspector, PBAPS

ATTACHMENT 1

Exelon Generation Company, LLC (Exelon)
License Renewal Application (LRA)
Peach Bottom Atomic Power Station (PBAPS), Units 2 and 3

Request for Additional Information

B.2.11 Susquehanna Substation Wooden Pole Inspection Activity

RAI B.2.11-1

The LRA states that the wooden pole is inspected for loss of material due to ant, insect, and moisture damage, and for change in material properties due to moisture damage. Section A.1.2.3.3, "Parameters Monitored or Inspection," of NUREG 1800 states that the parameters to be monitored or inspected should be identified and linked to degradation of particular structures and component intended function(s) (Branch Technical Position on Aging Management Program Elements). Identify what kind of parameters and material properties are monitored or inspected. Also, explain how the buried part of the wooden pole is monitored/inspected.

Response:

Aging management activities for wooden poles consist of visual inspections, sounding and, if required, boring and excavation activities.

Each inspection consists of a visual inspection of the entire pole from the ground up. Parameters inspected include shell rot, decay pockets, heart rot, rotten butt, cracked or broken arms or braces, mechanical damage, ground-line decay, split tops, etc. Any inspected item which may limit the life of the pole, or which requires immediate attention in the interest of safety, is recorded and reported.

Each pole is sounded by striking each quadrant of the pole surface several times with a sounding hammer around the circumference from the ground-line to as high as the inspector can reach. If sounding indicates internal decay or a hollow pole, borings may be made.

Poles found to require boring will have at least one boring in each pole, beginning at (not above) the ground line. Additional borings are made when needed to determine the extent of decay in a pole.

If poles are found to have ground-line decay, they are excavated and inspected 18" below the ground line. The pole is sounded, and if internal decay is suspected, the pole is bored to allow for further analysis.

RAI B.2.11-2

Section A.1.2.3.5 of NUREG 1800 states that it is necessary to confirm that timing of the next scheduled inspection will occur before a loss of structure or component intended functions (Branch Technical Position on Aging Management Program Elements). Provide a justification for the ten-year inspection interval of the wooden pole.

Response:

The typical life of a wooden pole, based on industry experience, is 30-40 years. If the pole is inspected and treated with a pesticide, fumigant, or preservative solution as required every ten years, it should last 10 to 15 years longer.

Our experience over several decades has indicated that a ten-year inspection interval is adequate.

The Susquehanna wooden pole was installed in 1994. The first inspection will be scheduled to occur in 2003, and then every ten years thereafter.

RAI B.2.11-3

Section A.1.2.3.6, "Acceptance Criteria," of NUREG 1800 states that the acceptance criteria and its basis should be described (Branch Technical Position on Aging Management Program Elements). Provide a brief description of the acceptance criteria in terms of (1) assessing the severity of the observed degradations and (2) determining whether corrective action is necessary.

Response:

An approved wooden pole maintenance contractor experienced in the inspection, treatment, and reinforcement of wooden poles performs the pole inspection. Personnel handling treatment material are licensed pesticide applicators.

The inspector, through a combination of visual, sounding, boring, and excavation activities, determines the condition of the pole. Any parameter inspected, such as shell rot, decay pockets, heart rot, rotten butt, cracked or broken arms or braces, mechanical damage, ground-line decay, split tops, etc, which may limit the life of the pole or which requires immediate attention in the interest of safety, is recorded and reported. If sounding indicates internal decay, or a hollow pole, boring will proceed to determine the extent of the decayed area. Pesticide treatment will occur as required.

Any pole (except poles requiring replacement) found to contain ants or termites is flooded with an effective preservative solution in the cavities where the ants or termites are found.

Any pole determined to have internal decay will receive fumigant treatment.

Each wooden pole that is inspected receives a condition tag. The condition tag describes the pole condition as found by the inspector. The tag also describes if the pole has received treatment such as fumigant treatment, externally or internally treated, or ground-line treated. Based on remaining shell thickness (circumference) and pole loading, poles can be tagged as either requiring reinforcement or replacement.

RAI B.2.11-4

The LRA stated that the AMP will be enhanced, but the LRA did not provide sufficient detail to allow the reviewer to assess the adequacy of the activities. Provide a description of how the Susquehanna Substation Wooden Pole Inspection Activity (SSWPIA) will be enhanced.

Response:

PECO, which is a different entity than PBAPS, currently inspects wooden poles in its territory on an approximate ten-year frequency. The enhanced inspection activity will be an activity to instruct PBAPS to arrange for PECO to conduct a pole inspection prior to the end of the ten-year period to ensure the inspection is completed within that ten-year period. This will ensure that the intended function of the Susquehanna wooden pole is maintained during the period of extended operation.

B.3.1 Torus Piping Inspection Activities

RAI B.3.1-1

There is inconsistency between Tables 3.2-2 and 3.2-5 of the LRA and the description of Program Scope in the Torus Piping Inspection Activities AMP. Tables 3.2-2 and 3.2-5 of the LRA show that the AMP is credited to manage the loss of material for the components in the core spray and residual heat removal systems. The "*Program Scope*," however, does not include these two systems. Why are the torus piping of the core spray and residual heat removal systems not included in the program scope?

Response:

The torus piping of the core spray (CS) and residual heat removal (RHR) systems is bounded by the scope of the Torus Piping Inspection Activities but is not in the one-time inspection scope. This is because the internal environment of the piping of the CS and RHR systems above the water line is torus grade water. The internal environment of the Main Steam SRV, HPCI turbine, and RCIC turbine above the water line is wetted gas. It was determined that the piping with wetted gas both internally and externally would be more susceptible to loss of material at the water-gas interface and would therefore bound the other piping in the torus. This potential loss of material at the water-gas interface is due to normal, small torus water level changes that alternately wet and dry the piping. For the CS and RHR piping, this effect only occurs on the outside of the pipe, and for Main Steam SRV, HPCI turbine, and RCIC turbine the effect occurs on both the inside and the outside of the piping. This AMP is credited in the system tables because the results of the one-time inspection will be evaluated for applicability to the CS and RHR piping in the torus as well as the other piping described in the AMP. Apparent unacceptable indications of corrosion will be evaluated by further engineering analysis for their applicability to CS, RHR, Main Steam SRV, HPCI turbine and RCIC turbine piping and, if warranted, additional inspections will be performed.