Exelon Nuclear
200 Exelon Way
Kennett Square, PA 19348

www.exeloncorp.com

Exelon Nuclear

10CFR54

April 29, 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 Related to Appendix B Aging Management Activities

Reference: Letter from R. K. Anand (USNRC) to M. P. Gallagher (Exelon), dated March 12, 2002

Dear Sir/Madam:

Exelon Generation Company, LLC (Exelon) hereby submits the enclosed responses to the request for additional information transmitted in the reference letter. For your convenience, attachment 1 restates the questions from the reference letter 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 5-2-02

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

IE23

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.1.8 Inservice Inspection (ISI) Program

RAI B.1.8-1

The AMP manages the aging effects for the ASME Class 1, 2, and 3 pressure retaining components exposed to various environments that include reactor coolant, borated water, raw water, steam, wetted gas, sheltered, and outdoor environments. The AMP, however, does not cover the ASME Class 1, 2, and 3 pressure retaining components exposed to the condensate storage tank (CST) water or torus water environments. Justify why these components have not been included.

Response:

The aging management activity for the pressure retaining components exposed to the condensate storage water environment is the Condensate Storage Tank Chemistry Activities (LRA Appendix B.1.4). We have operating experience that verifies the effectiveness of the CST chemistry activities. Piping inspections are routinely performed in the ISI and FAC programs and have been satisfactory. Much of this piping is ASME Section XI class 2 piping, which requires periodic inspections of welds and pressure tests to verify integrity. In addition, the FAC program performs inspections at several susceptible locations to verify required wall thickness. We believe that the CST chemistry activities are sufficient to adequately manage aging. The routine inspections performed for piping in the condensate storage water environment verify the effectiveness of the program (see response to RAI B1.4-1).

The aging management activity for the pressure retaining components exposed to the torus water environment is the Torus Water Chemistry Activities (LRA Appendix B.1.5). We have operating experience that verifies the effectiveness of the torus water chemistry activities. Piping inspections are routinely performed on these systems in the ISI and FAC programs and have been satisfactory. Most of this piping is ASME Section XI class 2 piping, which requires periodic inspections of welds and pressure tests to verify integrity. In addition, the FAC program inspects several locations on these systems at susceptible locations to verify required wall thickness. We believe that the torus water chemistry activities are sufficient to adequately manage aging. The routine inspections performed for the piping in the torus grade water environment verify the effectiveness of the program (see response to RAI B1.5-2).

RAI B.1.8-2

In the LRA, it is stated that the ISI program provides aging management for ASME Class 1 components in the HPCI, core spray, PCIS, RCIC, and RHR systems. Address why all of the ASME Class 2 and 3 components of these systems are not included within the scope of the ISI AMP. ASME Section XI requirements generally apply to Class 1, 2, and 3 components.

Response:

The Peach Bottom ISI Program includes requirements for ASME Class 1, 2 and 3 components. However, only the ISI activities associated with Class 1 components of the HPCI, Core Spray, PCIS, RCIC and RHR systems are credited for license renewal aging management. The aging management review determined that, for the non-Class 1 components in these systems, other aging management activities such as Reactor Coolant System Chemistry (Appendix B.1.2), Condensate Storage Tank Chemistry Activities (Appendix B.1.4), Closed Cooling Water Chemistry (Appendix B.1.3), or Torus Water Chemistry Activities (Appendix B.1.5) are sufficient to manage aging. Plant specific operating experience with these systems indicates that controlling water chemistry has been effective in minimizing aging effects. Where piping within the torus is subject to potential aging effects at the gas-water interface, this aging effect is managed by the Torus Piping Inspection Activities (Appendix B.3.1). Other aging management activities are applied to specific components, such as Heat Exchanger Inspection Activities (Appendix B.2.12) or HPCI and RCIC Turbine Inspection Activities (Appendix B.2.10). This combination of aging management activities is considered sufficient to manage aging of the non-Class 1 portions of the HPCI, Core Spray, PCIS, RCIC and RHR systems.

RAI B.1.8-3

In the LRA, it is stated that the ISI program is augmented to address GL 88-01. Describe the aging management program activities related to GL 88-01 in sufficient detail to allow the staff to assess the adequacy of the activities.

Response:

GL 88-01 applies to piping that meets the following criteria:
austenitic stainless steel, and
four inches or larger in diameter, and
contains reactor coolant above 200°F during power operation.

GL 88-01 also applies to reactor vessel attachments and appurtenances such as jet pump instrumentation assemblies and head spray and vent components.

The PBAPS Inservice Inspection program was augmented to include various additional requirements, including these GL 88-01 inspections.

There is significant overlap in systems and portions of systems that are required to be inspected by both GL 88-01 and ASME Section XI (Code). Much of the piping in GL 88-01 scope is ASME Class 1. ASME Class 1 austenitic stainless steel piping subject to GL 88-01 is not included in the ASME Class 1 weld count. The 25% sample population required for Class 1 piping will not include any welds in the GL 88-01 program scope. This is acceptable because:

- Any piping within the scope of GL 88-01 will be inspected at a rate that meets or exceeds that specified by the Code.
- Surface examinations will be performed once per interval on each weld selected for UT examination that is within the Class 1 boundaries. Weld overlay inspections will be in accordance with the criteria in GL 88-01; the Code does not address these welds.

- Qualification requirements for examination personnel meet or exceed Code requirements.
- Flaw evaluations performed on piping subject to GL 88-01 must satisfy ASME Code Class 1 rules.
- Examination results are provided to the NRC.
- The American Nuclear Insurers Inspector (ANII) will review the Class 1 piping examinations as specified by Section XI.

RAI B.1.8-4

Operating experience is one of the 10 attributes of an AMP. The LRA stated that PBAPS has implemented extensive inspection programs through the ISI program to identify IGSCC. The LRA, however, does not describe the operating experience and the effectiveness of the inspection program in the identification of IGSCC. Address the operating experience and the effectiveness of the inspection program in the identification of IGSCC.

Response:

Prior to 1988, cracking attributed to IGSCC was found in stainless steel recirculation and RHR system piping. Portions of the 304 stainless steel recirculation system, RWCU, and RHR piping were replaced with more IGSCC resistant, low carbon 316 stainless steel.

Subsequent to 1988, IGSCC has been identified in the Reactor Water Cleanup system, Core Spray downcomer piping, core shroud and jet pump riser piping. The identified cracking was dispositioned as meeting the applicable acceptance criteria either by repair or analysis. The ISI Program, including the augmented inspections to address the requirements of GL 88-01, has been effective in identifying IGSCC prior to loss of system intended functions.

RAI B.1.8-5

The LRA does not specify whether small bore piping is included within the scope of the ISI program. The staff believes that a one-time inspection is appropriate for small bore piping (diameter < 4 inches) because it is exempted from ASME Code Section XI ISI and, thus, does not receive volumetric examination during ISI. State whether small bore piping is included within the scope of the ISI program and identify the AMP that will be used for small bore piping. If not, provide the AMP that is used to manage aging in small bore piping.

Response:

Small bore piping is included in the scope of the ISI Program. The ISI program requires system hydrostatic pressure testing that includes the small bore piping in accordance with Section XI of the ASME Code. In addition, aging of small bore piping is managed by aging management activities such as Reactor Coolant System Chemistry (Appendix B.1.2), Condensate Storage Tank Chemistry Activities (Appendix B.1.4), Closed Cooling Water Chemistry (Appendix B.1.3), or Torus Water Chemistry Activities (Appendix B.1.5) as applicable. Plant specific operating experience indicates that controlling water chemistry has been effective in minimizing aging effects. We believe these programs are adequate in managing aging of small bore piping in the scope of license renewal.

B.1.9 Primary Containment Inservice Inspection Program

RAI B.1.9-1

The LRA is not specific as to whether the examination and testing of the pressure retaining bolting associated with the primary containment structure are included as part of the program. Clarify whether the examination and testing of the pressure retaining bolting associated with the primary containment structure are included as part of the program.

Response:

The scope of the PBAPS Primary Containment Inservice Inspection Program includes pressure retaining bolting. Visual examination of pressure retaining bolting is in accordance with IWE 3510.1. Testing is in accordance with 10CFR Part 50 Appendix J, Type B test.

RAI B.1.9-2

In describing the "Operating Experience," the AMP discusses the degradation of coating in the containment torus. The maintenance of coating can act as the first line of defense against the metal corrosion in the primary containment structure. Explain why the maintenance of coating is not considered as the first line of defense against the metal corrosion in the primary containment structure. Why isn't maintenance of coating included as part of the "*Preventive Actions?*"

Response:

Exelon recognizes the benefit of the primary containment suppression chamber (torus) protective coatings. The coating is a design feature of the torus shell, maintained in accordance with existing plant procedures and specification to ensure its effectiveness. However, the protective coating does not perform a license renewal intended function as defined in 10CFR54.4(a)(1), (2), or (3) and is not credited in the determination of aging effects requiring management for the torus.

RAI B.1.9-3

In describing "*Parameters Monitored/Inspected*," the AMP disregards monitoring the condition of protective coating; however, monitoring of the protective coating can act as the first line of observation in determining the potential degradation of metal surfaces of the primary containment. Justify why the protective coating on the primary containment surfaces should not be an element of *Parameters Monitored/Inspected.*"

Response:

As stated in response to RAI B.1.9-2, primary containment protective coating is not credited for aging management of primary containment surfaces. The Primary Containment ISI Program, implemented to satisfy the requirements of 10CFR50.55a is credited for managing aging of primary containment surfaces.

RAI B.1.9-4

The LRA refers to the ASME Code, Section XI, as guidance. Use of Subsection IWE of ASME Section XI for ISI of the pressure retaining metallic components of Class MC containment structure is mandated by 10 CFR 50.55a. Thus, the ASME Section XI requirements are not guidance. Explain how Subsection IWE has been incorporated into your ISI program (i.e., as a guidance document or as a mandatory document).

Response:

The PBAPS Primary Containment ISI Program complies with the requirements of 10CFR50.55a. The Program was developed in accordance with the 1992 Edition through 1992 Addenda of ASME, Section XI, Subsection IWA and IWE, for Inspection Program B. The Program is implemented through controlled plant procedures and engineering specification and subject to 10CFR Part 50, Appendix B Requirements. Compliance with these documents is mandatory.

RAI B.1.9-5

Under "*Operating Experience*," the LRA describes torus degradation found at the two PBAPS units in 1991, but does not provide sufficient information to permit the staff to evaluate the operating experience. Provide quantitative information regarding the torus degradation found at the two PBAPS units in 1991. Were these degradations dispositioned by corrective actions or by engineering evaluation? Was water chemistry the root cause of the degradation? In some cases, the staff has found the torus degradation near the strainers due to the stagnant water conditions. Describe the location of the degradation.

Response:

PBAPS examination program for wetted and submerged surfaces on the interior of the suppression chamber (torus) in both units was established in 1991. Underwater visual examinations were performed on the interior torus surfaces, and pit depth measurements were taken on one square foot evaluation areas that were selected in each of the 16 bays, based on having the greatest concentration of deep pits. In conjunction with underwater examinations, ultrasonic thickness measurements were taken on the defined evaluation areas from the outside of the torus at the pitted areas. Examination results showed that the maximum measured pit depth approached a depth of 10% of the shell's wall thickness. The average measured pit depth in Unit 2 torus was 25 mils, while the average measured pit depth in Unit 3 was 31 mils.

The degradations were dispositioned by a combination of corrective actions and engineering evaluation. The evaluation concluded that the structural integrity of the torus in both units was maintained, and continued operation was justified. The evaluation also established inspection methodology and acceptance criteria for future examinations. These requirements are incorporated in the "augmented" inspection of the torus under the Primary Containment ISI Program.

Water chemistry is determined to be the primary cause of the degradation as evidenced by the reduced rate of corrosion since 1991 when improved water chemistry controls were established. However, other factors such as possible loss of protective coatings, lamination or potential flaws in the rolled steel plate, and micro-organisms present in the accumulated sludge may have contributed to the degree of the degradation.

As for location of the degradations, our inspections found the pits to be randomly distributed along the submerged surface of the torus. The worst pits were found in areas where protective coating was lost due to damage during construction or misapplication. These degradations were found near the bottom of the torus at approximately 30-degree angle from the vertical. The area near the strainers was not significantly different from the rest of the torus.

RAI B.1.9-6

In describing the operating experience regarding the torus degradation, the LRA states, "The interior surfaces were recoated and torus grade water chemistry was improved. Subsequent pressure suppression chamber inspections indicate that the rate of degradation has decreased significantly." Provide the rate of metal reduction and, assuming that rate continues in the future, provide the projected thickness of the torus shell in those areas at the end of the extended period of operation. Compare the projected thickness to the thickness required to support the current licensing basis for the affected systems.

Response:

PBAPS Unit 2 torus shell was inspected in October 1998 to evaluate pit growth rate since the 1991 inspection. The corrosion evaluation area selected for inspection contained 30 pits inspected in November 1991, eight (8) of which were repaired via application of underwater coating. The 1998 inspection results showed that coating repairs remained in tact. The average change in pit depth is less than 5 mils over the seven (7) year time period between inspections, or 0.7 mils annual rate. Actual pit depths from the 22 measured pits ranged from a low of 17.0 mils to a high of 41.1 mils.

Similarly, PBAPS Unit 3 torus shell was inspected in October 1997. The evaluation area inspected contained 18 pits, which were inspected in January 1991. The average change in pit depth is less than 3 mils over the six (6) year time period between inspections, or 0.5 mils annual rate. Actual pit depths from the 18 measured pits ranged from a low value of 16.3 mils to high value of 46.1 mils.

The design shell thickness of the immersion area of the torus is 675 mils. Using the average corrosion rates and deepest pits above, the projected estimated worst pit through the end of extended term of operation for Unit 2 is 65.6 mils (41.1 mils + 35 years x 0.7 mil) and 64.1 mils for Unit 3 (46.1mils + 36 years x 0.5 mils). Thus the minimum projected thickness at the pitted area at the end of 60 years is 609.4 mils for Unit 2 and 610.9 mils for Unit 3.

Engineering analysis shows that the impact of pits on local and global structural integrity of the torus is a function of the width of the pit, as well as its depth. Evaluation performed, after 1991 inspections, concluded a pit depth of 65 mils has no impact on torus structural integrity regardless of the pit diameter. Thus, the overall thickness of the torus can be reduced by 65 mils without impacting its intended functions. This would indicate that control of torus water chemistry alone is adequate to manage aging of the torus shell loss of material. However, considering industry experience with torus degradations, as well as PBAPS past experience, the Primary Containment ISI Program (Augmented Inspections) is considered more effective for managing this aging effect.

As a result, Exelon is committed to continued periodic inspection of the torus shell for loss of material as defined in Primary Containment ISI Program. Identified defects will be evaluated against established design basis criteria or corrected to ensure the intended functions of the torus are maintained through the extended term of operation.

RAI B.1.9-7

In describing the operating experience regarding the drywell degradation, the LRA states, "No failure of containment components due to the loss of material or failure of the moisture barrier inside the drywell due to the loss of sealing has occurred at PBAPS." However, operating experience can include degradation that is found and corrected. Provide additional information regarding the extent of degradation found on the drywell shell at the junction with the moisture barrier. What corrective actions have you taken to prevent the recurrence of this type of degradation in the future? If you disposed of such degradation by engineering evaluation, provide a summary of your engineering evaluation, and its projection for the end of the extended period of operation.

Response:

We have not identified any degradation on the drywell shell at the junction with the moisture barrier.

B.1.10 Primary Containment Leakage Rate Testing Program

RAI B.1.10-1 DELETED

RAI B.1.10-2

In "*Administrative Controls,*" the LRA states that all aging management activities are subject to administrative controls, which require formal reviews and approvals. The PBAPS Technical Specifications also require administrative controls for the Primary Containment Leakage Rate Testing Program. Provide information regarding which administrative controls will be used for this program during the extended period of operation.

Response:

PBAPS Technical Specifications require that "Primary Containment Leakage Rate Testing Program" be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B. This Technical Specifications requirement is implemented through controlled administrative station procedures and guidelines, which are referred to in LRA Appendix B.1.10.

RAI B.1.10-3

The staff has found that in BWR Mark 1 containments, the expansion bellows located in the vents between the drywell and the suppression pool are subjected to transgranular stress corrosion cracking (see NRC Information Notice 92-20: "Inadequate Local Leak Rate Testing"). Moreover, the staff has recognized that some of the bellow construction would require Type A testing for detecting such degradation of the bellows. Please provide the "operating experience" related to the condition of these bellows at PBAPS, and provide information regarding the leak rate testing of these bellows during the extended period of operation.

Response:

The PBAPS vent line bellows are 2-ply type, constructed to be tested locally, and subject to 10 CFR 50, Appendix J, Type B Test. The LLRT method implemented at PBAPS verifies no internal blockage of flow to avoid the inconsistency reported in NRC Information Notice 92-20. Recent Local Leak Rate Test (LLRT) records (1992, 1994, and 1998) for the Unit 2 vent line bellows indicate that leakage through each bellow is significantly less than the assigned administrative limit. Similar results were recorded for Unit 3 vent line bellows during the previous three LLRTs (1993, 1995, and 1999). Periodic Type A ILRT results have not shown inconsistencies with the LLRT results described in NRC Information Notice 92-20.

As stated in response to RAI-B.1.10-2, PBAPS Technical Specifications require that "Primary Containment Leakage Rate Testing Program" be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B. Type B Test (LLRT) is implemented for the vent line bellows in the current term of operation. Testing required by Technical Specifications will continue during the extended term of operation.

RAI B.1.10-4

The first sentence of LRA, UFSAR Supplement, Section A.1.10 states, "The primary containment leakage rate testing program is that portion of the PBAPS primary containment leakage rate testing program that is being credited for license renewal." It is not clear what portion of the program is not included and not credited for license renewal. It is the staff's understanding that the program includes all the primary containment leakage testing requirements as stipulated in the PBAPS Technical Specifications. Please clarify.

Response:

The Primary Containment Leak Rate Testing Program includes Type A, Type B and Type C tests for all of primary containment and isolation components. However, the only part of the program that is credited for license renewal is what is included the scope of the AMA App B.1.10, attribute 1. That is, the Program is credited for managing loss of material of pressure retaining boundaries of piping and components in a wetted gas environment for containment atmosphere control and dilution, RHR, and primary containment isolation systems. The Program is also credited for managing change in material properties and cracking of gaskets and O-rings of the primary containment pressure boundary access penetration points including the drywell head, the equipment hatch, the airlock, control rod drive removal hatch, drywell access hatch, stabilizer inspection ports and the two access hatches in the pressure suppression chamber.

B.1.14 Crane Inspection Activities

RAI B.1.14-1 DELETED

RAI B.1.14-2

It is stated in LRA Section B.1.14, that the "crane inspection activities comply with the requirements of ASME Code, Sections B32.2, B30.11, B30.16 and B30.17." Describe the specific PBAPS plant procedures that implement these requirements for the overhead and gantry cranes.

Response::

PBAPS crane inspection activities are based on ASME B30.2, Chapter 2-2, Inspection, Testing, and Maintenance. The activities are divided into two general classifications as required by ASME B30.2:

(1) Frequent Inspections
(2) Periodic Inspections

Frequent inspections are performed on a frequency of 23-37 days, while Periodic Inspections are conducted yearly. PBAPS AMRs concluded that Periodic Inspections provide for prediction of the onset of degradation and for timely implementation of corrective actions to prevent loss of intended function. As a result, only Periodic Inspections are credited for managing the aging effects of passive components of the overhead cranes and the gantry crane during the extended term of operation. The scope of Periodic Inspections, as defined in PBAPS procedures, includes the following:

- Visual inspection of structural and mechanical components
- Visual inspection of electrical components
- Inspection of hooks
- Inspection of hoist ropes
- Inspection of welded link chain
- Lubrication of moving parts
- Operational testing

For each component listed above, PBAPS procedures identify the required inspection or testing activity to ensure their design or intended function is maintained. Structural and mechanical components (active and passive) are monitored for the following parameters consistent with ASME B30.2:

1. Deformed, cracked, corroded or loose structural members
2. Loose bolts or rivets
3. Cracked, distorted or excessively worn load blocks, sheaves, bearings or drums
4. Excessively worn, cracked or distorted parts such pins, shafts, gears or rollers
5. Worn, glazed or oil contaminated drums, lining/friction discs; abnormally worn pawls, cams, ratchets, or linkage; corroded, stretched or broken springs; piping or hose defects and loose fittings.
6. Brake fluid reservoir low
7. All locking, limiting, indicating and safety device damage or malfunction
8. Damage or excessive wear of drive sprocket, load sprocket or hand chain wheel
9. Monorail interlocking mechanisms, track switches, drop and section malfunctions
10. Misaligned or cracked rails; loose tie down bolts; flaking and side wear (full length of bridge and trolley rails)

11. Cracked or deformed bridge or trolley drive wheels; excessively worn flanges or wheel bearings
12. Excessive wear or deformation of monorail lower load carrying flange
13. Excessive wear of hoist carrier drive tires
14. Cracked, deformed or loose mechanical drive tires
15. Remove cover/inspection plate(s), if equipped, for each gear box and visually examine for excessively worn or damaged gears; damaged oil seals or excessively worn bearings
16. Visually examine gearbox shafts for evidence of binding and loose couplings

Parameters 1, 2, 10, and 12 apply to long-lived passive components of the overhead cranes and the gantry crane. These parameters are credited for license renewal.

ASME B30.2 requires that a designated person shall determine whether conditions found during inspection constitute a hazard and whether disassembly is required for additional inspection. Consistent with this requirement, PBAPS procedures require the Lead Maintenance Technician establish inspection criteria, for each crane monitored. Conditions that do not meet established criteria are considered abnormal. Abnormal conditions require immediate notification of maintenance supervision, corrective action, and documentation.

B.1.16 Maintenance Rule (MR) Structural Monitoring Program (SMP)

RAI B.1.16-1

The scope of the MR SMP does not discuss the inspection of inaccessible structural components. Structural components in contact with an aggressive soil/water environment may be subjected to aging effects such as cracking and loss of material.

(a) Provide an analysis of the soil/water environment.

(b) Describe the provisions of the MR SMP for inspecting normally inaccessible structures and components.

(c) If the MR SMP does not provide for inspections of inaccessible structural components, then describe the provisions of the program to ensure that the soil/water environment remains nonaggressive (e.g., periodic sampling of groundwater).

Response:

(a) Ground and river water (Conowingo pond) samples were tested in January 1968, in preparation for plant construction and recently, July 2000, to support PBAPS AMRs. The range of pH, sulfates and chlorides are as follows:

Period	pH	Sulfates, ppm	Chlorides, ppm
Jan 1968	7.2 - 7.6	10 – 41	14 – 22
Jul 2000	7.2 - 7.3	10 – 38	6 – 24

(b) PBAPS Maintenance Rule Structural Monitoring Program provides for walk-downs and visual inspection of accessible areas. Normally inaccessible structures and components are determined satisfactory based on satisfactory condition of similar accessible structures and components. If findings on accessible structures or components indicate that a potential degradation may be occurring in an inaccessible area, an evaluation will be performed as required by Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants". The aging management reviews did not identify unique aging effects for inaccessible structures and components. Thus, inspection of accessible structures and components is representative of both accessible and inaccessible structures and components.

(c) According to NUREG-1557, concrete degradation occurs in an aggressive environment, defined as (pH < 5.5, sulfates > 1500 ppm, and chlorides > 500 ppm). PBAPS ground and river water are non-aggressive as indicated by pH, sulfates, and chlorides test results provided in response to item (a) above. Furthermore, the pH, sulfates, and chlorides content of the water are significantly below the threshold limits for aggressive environment. Also, the data reflects over 31 years of operating experience (1968 – 2000) with no significant change in pH, sulfates, or chlorides. Therefore, future continued periodic sampling of ground and river water is not required. The fact that water chemistry has not changed significantly in 31 years provides reasonable assurance that pH, sulfates, and chlorides will remain within non-aggressive limits for concrete through the extended term of operation. As stated in 10CFR54.4 Statements of Consideration (SOC), 20 years of operational experience provides substantial amount of information and would disclose any plant-specific concerns with regard to age-related degradation.

RAI B.1.16-2

The acceptance criteria for the AMP states that the inspection results will be documented and evaluated by qualified personnel. Provide a description of the training and qualifications of the personnel that (1) perform the structural monitoring program walkdowns and (2) evaluate the adequacy of the walkdown procedures and findings.

Response::

PBAPS Maintenance Rule Structural Monitoring Program requires:

(1) Personnel who perform walkdowns (inspectors) be
   a. Qualified evaluators as described below, or
   b. Received instruction from qualified evaluator for performance of inspections.

(2) Personnel who evaluate the adequacy of the walkdown procedures and findings (Evaluators) have
   a. BS Degree in Civil, Structural or Mechanical Engineering with 2 years of relevant experience, or
   b. 5 years of civil/structural engineering experience.

B.2.4 Emergency Diesel Generator Testing and Inspection Activities

RAI B.2.4-1

It is stated in LRA Section B.2.4, Item (10) "*Operating Experience,*" that water and sediment have been observed during the fuel oil storage tank inspections at PBAPS. Describe the inspection procedures, including frequency and acceptance criteria for these inspections, in sufficient detail to enable the staff to verify that the aging effects of the potential presence of water in the storage tanks is being adequately managed.

Response:

Samples are taken from the bottom of the Emergency Diesel Generator fuel oil storage tanks once per 31 days in accordance with Technical Specification SR 3.8.3.5. The acceptance criterion is less than 100 ml of water in 'Bacon Bomb' sample bottle. Water is pumped from the tank bottom if criteria are exceeded until liquid changes from water to clean fuel oil, and then the tank bottom is again sampled. This sampling and water removal is performed by procedure ST-O-52D-600-2, "Emergency Diesel Generator Main Fuel Oil Storage Tank Water Removal."

The fuel oil storage tanks are drained and cleaned every 10 years. Residual fuel oil and sludge is removed, the tank is washed with a cleaning solution, and finally wiped until clean and dry. The tank cleaning procedure is M-052-013, "Standby Diesel Generator Fuel Oil Storage Tank Cleaning."

<u>Operating Experience</u>

Based on a teleconference with the NRC staff on April 3, 2002, the following additional information is provided:

Operating experience considered here is the plant specific experience with implementation of the Emergency Diesel Generator Inspection activities. This plant specific operating experience demonstrates the effectiveness of the activities in managing the identified aging effects. This demonstration is consistent with the guidance of NEI 95-10, Revision 3, Section 4.2.1.2, "Demonstrate that the Effects of Aging are Managed" which states: "Operating experience of the program/activity, including past corrective actions resulting in program enhancements, should be considered. It provides objective evidence that the effects of aging have been and will continue to be adequately managed." Regulatory Guide 1.188 endorses this guidance.

Furthermore, NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants", Appendix A.1 in the Branch Technical Position RLSB-1, under A.1.2.3.10 Operating Experience specifically requires operating experience with existing programs be discussed. This information is to be provided to support the conclusion that the effects of aging are managed adequately during the period of extended operation.

Operating experience is considered in the identification of aging effects. Aging effects are identified as part of the aging management review, based on guidance contained in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," including consideration of industry and plant specific operating experience. The LRA identifies the appropriate aging effects in Section 3, consistent with the guidance of NEI 95-10 Revision 3, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," endorsed by NRC Regulatory Guide 1.188. Industry and plant specific operating experience is accounted for in the selection of aging effects identified in the Section 3 Tables. The review of industry and plant specific operating experience is documented in the aging management review reports.

NRC generic communications are considered in our aging management reviews as part of industry operating experience. For example, the aging management review for EDG components in the lube oil and fuel oil environment includes consideration of NRC Information Notice 89-07 that documented industry problems with vibration induced failures in small tubing and fittings mounted on EDG engines. The PBAPS EDG engine maintenance procedure includes specific steps for verifying the condition of small piping, tubing and fittings mounted on the engines to detect external cracking or loss of material due to vibration induced rubbing or fretting.

B.2.6 Door Inspection Activities

RAI B.2.6-1

In the door inspection activities, the LRA excluded the inspection of doors in sheltered environments for loss of material. In LRA Section 3.15.4, you have identified carbon steel as the material of construction for these doors. Carbon steel door components could be susceptible to corrosion and wear in moist environments and other environments containing borated water, chlorides, etc. In addition, Appendix A of NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures," (industry-wide experience) clearly indicates that structural steel is subjected to corrosion under the ranges of temperature and humidity that may occur even in sheltered environments in nuclear power plants. Further, hinges and latches could be susceptible to wear and erosion, even under a sheltered environment. Provide justification for excluding inspection of doors in the sheltered environment from the door inspection activities.

Response:

PBAPS aging management reviews did not exclude doors from the scope of "Door Inspection Activities" without considering the actual environment. Instead the reviews concluded, for PBAPS sheltered environment, that loss of material due to corrosion of doors is non-significant and requires no aging management. Technical justification is as follows:

Unlike the sheltered environment described in the RAI, PBAPS sheltered environment does not contain borated water or chlorides. The environment (see LRA Section 3.0) consists of indoor ambient conditions where doors are protected from outdoor moisture. The normal air temperature range is 65° F - 150° F and the relative humidity range is 10%-90%. We concur with NRC staff that carbon steel in sheltered environment is susceptible to loss of material due to corrosion. However, as explained in response to RAI–3.5.2-5, any loss of material is non-significant and will not result in a loss of intended function.

As for wear and erosion of hinges and latches, the components are considered active and are not subject to aging management review. For this reason, door inspection activities do not address their aging effects.

Exelon's position is that loss of material for carbon steel in PBAPS sheltered environment is non-significant and requires no aging management. The position is supported by AMRs performed in accordance with industry guidelines for implementing the requirements of 10 CFR Part 54, and by PBAPS operating experience. The position and its justification were discussed with NRC staff on a January 28, 2002 telephone call. The staff indicated that it does not agree with the position and requires a nominal aging management activity. Exelon continues to disagree in principal with the staff's position; however, to resolve this issue expeditiously the Door Inspection Activity (B.2.6) is revised to include monitoring of hazard barrier doors in sheltered environment for loss of material due to corrosion.

RAI B.2.6-2

The enhanced door inspection activities do not address the operating attributes of the doors, such as hinges, latches, and the operating mechanism of the door, which are also subjected to aging and fatigue related degradation. Provide justification for excluding these important parameters related to the intended function of the doors.

Response:

Door hinges, latches, and operating mechanisms are active components and are not subject to aging management review. For this reason, door inspection activities do not address their aging effects.

RAI B.2.6-3

The change in material properties of seals and gaskets cannot be assessed by visual inspection. It would require testing. Provide information related to detecting changes in material properties of seals and gaskets of the doors.

Response:

Door inspection activities require visual examination of watertight door gaskets for cracks, rips, tears, and other degradations that may cause loss of seal. Although these inspection criteria may not be a direct measurement of the gasket change in material properties, it is a good indicator of the gasket's physical condition and its ability to provide an adequate seal. Gaskets are repaired or replaced if upon examination their condition indicates loss of seal potential.

RAI B.2.6-4

The LRA states that doors are inspected "periodically." This description is not sufficient to allow the staff to evaluate the effectiveness of the monitoring of degradation of the doors. Provide information regarding the frequency of performing the door inspections.

Response:

Door inspection activities are performed on a frequency of 4 years or less. The frequency is consistent with the frequency of PBAPS Maintenance Rule Structural Monitoring Program (B.1.16) and industry practices for implementing the requirements of 10CFR50.65 for structures. The frequency is selected to ensure, with reasonable assurance, that aging degradation of hazard barrier doors will be detected before there is a loss of intended functions.

B.2.9 Fire Protection Activities

RAI B.2.9-1

It is stated in LRA Section B.2.9 that functional testing for flow blockage will be conducted for sprinkler heads that have been in service for 50 years. Clarify if this testing would be done for all sprinkler heads that have been in service for 50 years, or on a sampling basis. Will this test be conducted in a laboratory or would it be a field test? This information would enable the staff to verify compliance with NFPA-25 requirements. Also, indicate whether or not the test and replacement of these sprinklers would fully comply with the NFPA requirements.

Response:

Sprinkler head testing will be done on a sampling basis in accordance with Section 2-3.1 of NFPA-25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems." Testing will be performed in a laboratory. The sprinkler head testing will comply with the sampling and frequency requirements of NFPA-25, Section 2-3.1.

RAI B.2.9-2 Deleted.

RAI B.2.9-3

It is not clear to the staff whether piping supports and hangers in the fire protection piping system are within the scope of the AMPs for component supports. Please verify that all piping supports and hangers in the fire protection piping system are covered by the aging management programs for the component supports. If not, discuss the specific AMPs for the piping supports and hangers in the fire protection system.

Response:

The piping supports and hangers in the fire protection system piping within the scope of license renewal are covered by the aging management review for component supports, with applicable aging management programs identified in the LRA Table 3.5-13.

RAI B.2.9-4

Describe the specific acceptance criteria for the timely detection of cracking, delamination, and separation of the fire barrier penetration seals in sufficient detail to allow the staff to evaluate whether the aging effects are adequately managed.

Response:

Specified quantities of fire barrier penetration seals are visually inspected every 24 months as indicated in LRA Section B.2.9, "Fire Protection Activities". Each penetration seal, selected for inspection, is compared to its original installation detail drawing. Inspection and acceptance criteria are indicated on the drawings and depend on seal materials and seal configuration. Specific visual inspection and acceptance criteria for silicone type seals are:

- Verify silicone seal is in place
- Verify there are no voids greater than a depth of ¼" in the surface of the seal
- Verify that shrinkage of seal away from items which penetrate the seal (cables,

conduits, pipe, tubing, etc..) is less than 1/8" and no deeper than ¼"
- Verify that shrinkage of seal away from penetration surface (concrete or embedded sleeve) is less than 1/8" and no deeper than ¼".

Visual inspection and acceptance criteria for grout/cement type seals are:
- Verify grout seal is in place
- Verify shrinkage of the grout away from the penetrating items is less than 1/8" and no deeper than ½"
- Verify shrinkage of the grout away from the penetration surface is less than 1/8" and no deeper than ½".
- Verify there are no cracks wider that 1/8" in the surface of the seal.
- If an existing void or crack is greater than ½" deep, verify that the depth of sound grout is a least 8".

Similar inspection and acceptance criteria are specified for other fire barrier penetration seal types to ensure their fire protection intended function is maintained. It is relevant to note that PBAPS operating experience has not identified age related degradation of fire barrier penetration seals. Instead, the materials have proven to be age independent, consistent with NRC letter SECY-96-146, "Technical Assessment of Fire Barrier Penetration Seals in Nuclear Power Plants" findings.

B.2.10 HPCI and RCIC Turbine Inspection Activities

RAI B.2.10-1

In the review of aging management results for RCIC system (Section 3.2, table 3.2-1, p. 3-32 of the LRA), the HPCI and RCIC turbine inspection activities AMP is listed as the aging management program for lubricating oil tanks with lubricating oil as the applicable environment. Wetted gas environment is also in the program scope of the AMP. Please identify the reference to the AMP being applied to components in a wetted gas environment.

Response:

LRA Table 3.2-1 identifies a number of carbon steel and stainless steel components in a wetted gas environment. For carbon steel components in a wetted gas environment, the applicable aging management activity is referenced in the table. The aging management review has determined that the stainless steel components in the HPCI system (LRA Table 3.2-1), that are exposed to an internal environment of wetted gas, do not have any aging effects that require aging management. Therefore, no aging management activity is identified for these components in Table 3.2-1.

RAI B.2.10-2

In the LRA, it is stated that the HPCI and RCIC turbine inspection activities consist of visual inspections of the turbine casings and the HPCI lubricating oil tank internals for evidence of loss of material. The LRA did not provide sufficient information to permit the staff to evaluate the effectiveness of the inspection activities. At what level is the visual inspection (e.g., VT-1, etc.) conducted?

Response:

The visual inspections are performed by qualified maintenance technicians in accordance with inspection procedures. There is no VT requirement in the procedures.

RAI B.2.10-3

The LRA did not provide sufficient information to permit the staff to evaluate the effectiveness of the inspection activities related to the lubricating oil tank internals. How will the inspection of the lubricating oil tank internals be conducted? Is UT methodology also used as part of the inspection procedures?

Response:

The inside of the HPCI oil reservoir is cleaned with lint free rags and inspected for signs of corrosion, scaling, or paint degradation. UT methodology is not a requirement in the inspection procedure.

RAI B.2.10-4

It is stated in the LRA that visual examinations of the turbine casings, lubricating oil tank, and flexible hoses are conducted on a periodic basis. What is the frequency of the examinations?

Response:

The HPCI and RCIC turbine maintenance is performed every 8 years. This frequency is based on the plant specific operating and maintenance experience with the HPCI and RCIC turbines. The component inspections are scheduled as part of the turbine maintenance.