March 12, 2002

APPLICANT: Exelon Generation Company, LLC (Exelon)

FACILITIES: Peach Bottom Atomic Power Station, Units 2 and 3

SUBJECT: TELECOMMUNICATION WITH EXELON GENERATING COMPANY TO DISCUSS INFORMATION IN THEIR LICENSE RENEWAL APPLICATION ON SECTION 3.3, AGING MANAGEMENT OF AUXILIARY SYSTEMS AND SECTION 3.4, AGING MANAGEMENT OF STEAM AND POWER CONVERSION SYSTEMS

On January 22, 2002, after the NRC staff reviewed information provided in Sections 3.3 and 3.4 of the license renewal application (LRA), a conference call was conducted between the staff and representatives of Exelon Generating Company to clarify information presented in the application pertaining to Section 3.3 Aging Management of Auxiliary Systems and Section 3.4 Aging Management of Steam and Power Conversion Systems. The information discussed, the applicant's responses, and the follow-up actions are in Attachment 1.

A draft of this telephone conversation summary was provided to the applicant to allow them the opportunity to comment on the contents of its input prior to the summary being issued.

/***RA***/

Raj K. Anand, Project Manager
License Renewal and Environmental Impacts Program
Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation

Docket Nos. 50-277 and 50-278

Attachments: As stated

cc w/attachments: See next page

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D. Thatcher
G. Galletti
B. Thomas
R. Architzel
J. Moore
R. Weisman
M. Mayfield
A. Murphy
W. McDowell
S. Droggitis
S. Duraiswamy
RLEP Staff

Peach Bottom Atomic Power Station, Units 2 and 3
cc:

Mr. Edward Cullen
Vice President & General Counsel
Exelon Generation Company, LLC
300 Exelon Way
Kennett Square, PA 19348

Mr. J. Doering
Site Vice President
Peach Bottom Atomic Power Station
1848 Lay Road
Delta, PA 17314

Mr. G. Johnston
Plant Manager
Peach Bottom Atomic Power Station
1848 Lay Road
Delta, PA 17314

Mr. D. A. Henry
Regulatory Assurance Manager
Peach Bottom Atomic Power Station
1848 Lay Road
Delta, PA 17314

Resident Inspector
U.S. Nuclear Regulatory Commission
Peach Bottom Atomic Power Station
P.O. Box 399
Delta, PA 17314

Regional Administrator, Region I
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Mr. Roland Fletcher
Department of Environment
Radiological Health Program
2400 Broening Highway
Baltimore, MD 21224

Correspondence Control Desk
Exelon Generation Company, LLC
200 Exelon Way, KSA 1-N-1
Kennett Square, PA 19348

Chief-Division of Nuclear Safety
PA Dept. of Environmental Protection
P.O. Box 8469
Harrisburg, PA 17105-8469

Board of Supervisors
Peach Bottom Township
575 Broad Street Ext.
Delta, PA 17314-9203

Public Service Commission of Maryland
Engineering Division
6 St. Paul Center
Baltimore, MD 21202-6806

Mr. Richard McLean
Power Plant and Environmental Review Division
Department of Natural Resources
B-3, Tawes State Office Building
Annapolis, MD 21401

Dr. Judith Johnsrud
National Energy Committee, Sierra Club
433 Orlando Avenue
State College, PA 16803

Manager-Financial Control & Co-Owner Affairs
Public Service Electric and Gas Company
P.O. Box 236
Hancocks Bridge, NJ 08038-0236

Mr. Frederick W. Polaski
Manager License Renewal
Exelon Corporation
200 Exelon Way
Kennett Square, PA 19348

Mr. Jeffrey A. Benjamin
Vice President-Licensing
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

Mr. Charles Pardee
Senior Vice President
Mid-Atlantic Regional Operating Group
Exelon Generation Company, LLC
200 Exelon Way, KSA 3-N
Kennett Square, PA 19348

Mr. John Skolds
Chief Operating Officer
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

Mr. William Bohlke
Senior Vice President, Nuclear Services
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

Mr. James Meister
Senior Vice President, Operations Support
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

Mr. Alan Nelson
Nuclear Energy Institute
1776 I Street, Suite 400
Washington, DC 20006

SUMMARY OF TELECOMMUNICATION WITH
EXELON GENERATING COMPANY
PEACH BOTTOM UNITS 2 AND 3

3.3 AUXILIARY SYSTEMS (General)

RAI-XXX

Clarify whether any of the auxiliary systems discussed in Section 3.3 of the LRA are within the category of seismic II over I SSCs as described in position C.2 of Regulatory Guide 1.29. Based on the information provided in Section 2.1.2.1 of the LRA, it appears that the applicant has included the pipe supports for seismic II over I piping systems in the scope of license renewal. However, the seismic II over I piping segments are not included within the scope of license renewal. The staff's concern is that seismic II over I piping, though seismically supported, would be subjected to the same plausible aging effects as safety-related piping. For example, depending on piping material, geometrical configuration, operation condition such as water chemistry, temperature, flow velocity, and external environment, erosion and corrosion may be plausible aging effects for some seismic II over I piping. Those effects, if not properly managed, could result in age-related failures and adversely impact the safety functions of safety-related SSCs. The applicant is requested to provide justification for not including the seismic II over I piping segments within the scope of license renewal. Specifically, the applicant is requested to address how plausible aging effects associated with those piping systems, if any, will be appropriately managed.

Response:

Awaiting formal RAI per NRC scoping and screening methodology audit (see December 7, 2001, public exit meeting minutes dated December 14, 2001).

Discussion: The staff will issue a formal RAI.

RAI-XXX

Numerous ventilation systems discussed in Section 3.3 of LRA include elastomer components in the system. Normally ventilation systems contain elastomer materials in duct seals, flexible collars between ducts and fans, rubber boots, etc. For some plant design, elastomer components are used as vibration isolators to prevent transmission of vibration and dynamic loading to the rest of the system. The aging effects of concern for those elastomer components are change in material properties such as hardening and loss of strength and loss of material due to wear. The applicant has identified the aging effect of change in material properties. To manage that aging effect, the applicant relies on the periodic visual inspection and testing activities included in the aging management program, ventilation system inspection and testing activities. The applicant stated that the inspection interval is dependent on the component and the system in which it resides. The applicant also indicated that previous inspection and testing activities have detected damaged components and leakage in certain ventilation systems. The applicant is requested to clarify how it has considered the aging effect of loss of material due to wear for the applicable elastomer components. In addition, the applicant is requested to provide the frequency of the subject visual inspection and testing activities and to demonstrate

the adequacy of the frequency of those inspection and testing activities to ensure that aging degradation will be detected before there is a loss of intended function.

Response:

The applicant stated that the aging management review determined that the applicable aging effect for elastomer components in the ventilation systems was change in material properties due to loss of strength, resiliency, and elasticity. Loss of material due to wear was not identified as an applicable aging effect based on plant operating experience and operating conditions.

The deficiencies noted in the LRA Appendix B.2.3 "Ventilation System Inspection and Testing Activities" attribute 10 occurred in the 1980's before adequate PM activities were instituted in the early 1990's. Recent operating experience has been good, supporting the current PM frequencies.

As stated in the Appendix B.2.3 attribute 5, components in the standby gas treatment system and the control room emergency ventilation system are inspected and tested annually. Additionally, PM activities for the battery room and emergency switchgear ventilation, control room fresh air supply, ESW booster pump room and diesel generator room are performed every two years. PM activities for the pump structure ventilation fans are performed every four years. Since no failures have been identified since the current PM activities have been instituted, the existing activities and frequencies are adequate to detect any aging effects prior to loss of intended function.

Discussion: The applicant's response is acceptable. However, the staff will issue a RAI.

RAI-XXX

In Sections 2.3.3.18 and 3.3.18 of the LRA, the applicant describes the scope and the intended functions of cranes and hoists and their associated aging management review. However, in Section 4.0 of the LRA, the applicant has not identified a crane load cycle limit as a TLAA for the cranes within the scope of license renewal. Normally based on its design code, there is a specified load cycle limit at rated capacity over the projected life for the applicable crane. Therefore, it may be necessary to perform an evaluation of TLAA relating to crane load cycles estimated to occur up to the end of the extended period of operation. The applicant is requested to provide justification for not including the crane load cycle limit as an applicable TLAA.

Response:

The applicant stated that Exelon's initial TLAA review pursuant to 10CFR54.21(c) identified fatigue of cranes as a potential plant-specific TLAA. Further review of CLB documents showed that the cranes are designed to Service Class A, as defined in specification CMAA-70, ' Specification for Electric Overhead Traveling Cranes' and does not involve time-limited assumptions defined by the current term. Therefore the potential TLAA does not meet the six screening criteria defined in 10CFR54.3(a). On this basis we concluded fatigue of cranes is not a TLAA. The cranes were reviewed for cumulative fatigue as discussed in response to RAI 6.

Discussion: The applicant's response to RAI 6 addressed the concern of TLAA. However, the staff disagree with applicant's assertion that this issue is not a TLAA. The staff will isuue a formal RAI.

RAI 1

Part of the defense-in-depth strategy of fire protection is to protect structures, systems, and components important to safety in order to retain the plants capability to be safely shutdown in the event that a fire is not promptly extinguished. This protection may be provided by components such as fire penetration seals, fire walls, fire doors and fire wrap. Although Section B.2.9 of the application, Fire Protection Activities includes the inspection of fire penetration seals, fire doors and fire wraps, none of these components are included in either Section 2.3.3.7, Fire Protection System as components in the scoping and screening process or in Table 3.3.7 in Section 3.3 Aging Management of Auxiliary Systems as part of the aging management review results. In addition, the applicant did not include fire walls in either the aging management review or the description of fire protection activities. The staff requests that the applicant provide information supporting the exclusion of fire barrier components (fire penetration seals, fire walls, fire doors and fire wrap) from the aging management review.

Response:

The applicant stated that fire barrier components, including fire walls, fire penetration seals, fire doors, and fire wraps are within the scope of license renewal and were subject to aging management review. Fire walls are included as components in their respective structures and addressed in LRA Section 2.4, Tables 2.4-2, 2.4-3, 2.4-4, 2.4-5, 2.4-7, 2.4-9, 2.4-10, 2.4-11, and 2.4-12. Similarly, aging management review results for the walls are summarized in Section 3.5 of LRA.

Fire penetration seals, fire doors, and fire wraps are included in the "Hazard Barriers and Elastomers" structural commodity group described in LRA Section 2.4.14. The components are listed in Table 2.4-14. Their aging management review results are summarized in Table 3.5-14.

Discussion: The applicant's response is acceptable. No further action is needed.

RAI - 2

Section 3.3.7, Fire Protection System@ contains Table 3.3.7 that outlines the aging management review results. The applicant identifies valve bodies, piping, and sprinkler heads as components included in the aging management review. The staff requests that the applicant clarify whether the valves, piping, and spray heads of the water curtain system were included in the aging management review.

Response:

The applicant stated that the valves, piping and sprinkler heads (spray heads) of the water curtain systems were included in the aging management review.

Discussion: The applicant's response is acceptable. No further action is needed.

RAI – 3

Section 3.3.16, Emergency Diesel Generator@ containsTable 3.3.16 that outlines the aging management review results. For various components (valve bodies, strainer screens, piping, and vessels) the applicant identifies loss of material as an aging effect of carbon steel in moist environments such as closed cooling water and wetted gas. However, the applicant does not identify cracking as an aging effect in these same moist environments or in the outdoor environment. For example, for valve bodies intended to function as a pressure boundary in the closed cooling water environment, the applicant identified loss of material and cracking as aging effects for stainless steel, but identified only loss of material as an aging effect for carbon steel. In addition, although the applicant identifies loss of material and cracking as aging effects for carbon steel piping in the lubricating and fuel oil environments, the applicant does not identify loss of material as an aging effect for lubricating oil vessels or cracking as aging effects for lubricating and fuel oil vessels. The staff requests the applicant to provide information that supports the exclusion of the aging effects as described. The table below summarizes the component groups that the staff requests the applicant to address.

Page	Component Group	Component Intended Function	Environment	Materials of Construction	Excluded Aging Effect(s)
3-97	Casting and Forging: Valve Bodies	Pressure Boundary	Closed Cooling Water	Carbon Steel	Cracking
3-99	Casting and Forging: Strainer Screens	Filter	Wetted Gas	Carbon Steel	Loss of Material
3-109	Piping: Pipe	Pressure Boundary	Buried	Carbon Steel	Cracking
3-109	Piping: Pipe	Pressure Boundary	Closed Cooling Water	Carbon Steel	Cracking
3-110	Piping: Pipe	Pressure Boundary	Outdoor	Carbon Steel	Loss of Material and/or Cracking
3-111	Piping Specialties: Drain Traps Expansion Joints	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking
3-111	Vessel: Expansion Tank	Pressure Boundary	Closed Cooling Water	Carbon Steel	Cracking
3-111	Vessel: Fuel Oil Day Tank	Pressure Boundary	Fuel Oil, Buried	Carbon Steel	Cracking
3-111	Vessel: Lubricating Oil Tank	Pressure Boundary	Lubricating Oil	Carbon Steel	Cracking
3-112	Vessel: Air Receivers	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking
3-112	Vessel: Silencers	Pressure Boundary	Wetted Gas	Carbon Steel	Cracking

Response:

The applicant stated that cracking is not identified as an applicable aging effect in NUREG-1801 “Generic Aging Lessons Learned (GALL) Report” for carbon steel in any of the environments listed in the RAI. Under certain conditions, cracking due to vibration is an applicable aging effect for the emergency diesel generators as described in NRC Information Notices 89-07 and 98-43. For this reason, cracking was identified as an aging effect for certain components mounted on or near the diesel engines.

For the strainer screen, loss of material was not considered an applicable aging effect because it is in the diesel starting air system piping which accumulates moisture upstream of this strainer in the air receiver tank which is blown down daily to remove any moisture. Reference Appendix B.2.4 for a description of this activity. Thus, loss of material was not considered significant for this component.

Discussion: The staff indicated that the applicant provide further technical basis for exclusion of the aging effects as described. The staff will issue a RAI.

RAI – 4

Section B.2.4 – moved to Appendix B.2.4 file

Discussion: The applicant's response is acceptable. No further action is needed.

RAI – 5

Section 3.3.17, Suppression Pool Temperature Monitoring System of the application contains Table 3.3.17 that outlines the aging management review results. The applicant identifies loss of material as an aging effect for penetration sleeves in torus water. However, the applicant does not identify cracking as an aging effect for the penetration sleeves even though they provide a fission product barrier. The staff requests the applicant to provide information supporting the exclusion of cracking as an aging effect for penetration sleeves.

Response:

The applicant stated that the thermowell sleeves penetrate the primary containment suppression chamber (torus) and are a part of the primary containment pressure boundary. For this reason, the thermowell sleeves are required to provide the fission product barrier intended function.

Their aging effects were evaluated as a sub-component of the primary containment structure (torus) since there is no piping associated with them. The evaluation concluded that cracking due to stress corrosion cracking (SCC), and intergranular cracking (IGA) is not applicable as explained below. Cracking due to cumulative fatigue is a TLAA and is included in the evaluation of torus penetrations described in LRA Section 4.6.1.

Stress corrosion cracking (SCC) occurs through the combination of significant tensile stress, a corrosive environment, and a susceptible (sensitized) material. SCC can be categorized as either IGSCC, or TGSCC, depending upon the primary crack morphology. The minimum level of stress required for SCC is dependent not only on the material but also on temperature and environment. EPRI TR-103840, "BWR Containment License Renewal Industry report; Revision, and NUREG –0313, "Technical Report on Material Selection and Processing Guidelines For BWR Coolant Pressure Boundary Piping" consider operating temperature above 200° F as a limit of probable significant cracking of susceptible stainless steels.

The stainless steel sleeves are exposed to torus water and reactor building, torus compartment, sheltered environment. The torus water operating temperature is less than 95° F and the operating temperature range for the sheltered environment is 65° F - 80° F. These temperatures are significantly lower than the 200° F referenced above. Consequently, SCC is not identified as an aging effect for the thermowell sleeves.

Intergranular attack (IGA) cracking is initiated by mechanisms similar to SCC. But again, the 95°F operating temperature is less than the temperature threshold where IGA can be expected.

Discussion: The applicant's response is acceptable. However, the staff will issue a RAI.

RAI – 6

Section 3.3.18, Cranes and Hoists of the application contains Table 3.3.18 that outlines the aging management review results. The applicant identifies loss of material as an aging effect for structural support members in both the outdoor and sheltered environments. However, the applicant does not identify fatigue as an aging effect for these steel structural members. The staff requests the applicant to provide information supporting the exclusion of fatigue as an aging effect for structural supports.

Response:

The applicant stated that as discussed in response to the last RAI-XXX above, cranes in the scope of license renewal meet the intent of the requirements CMAA-70, ' Specification for Electric Overhead Traveling Cranes'. The cranes are rated for Service Class A (Standby Service) and designed for 20,000 load cycles. These load cycles are based on lifts that are at or near their rated load capacity. At PBAPS the cranes are predominantly used to lift loads, which are significantly lower than their rated load capacity. Thus the number of lifts at or near their rated load is low as compared to the 20, 000 load cycles. For example, we conservatively estimated that the reactor building cranes will undergo less than 5000 load cycles in 60 years based on the number of qualified lifts during refueling outages, handling of spent fuel storage cask, and testing. The other cranes are expected to experience significantly less load cycles than the reactor building cranes. Consequently cumulative fatigue damage is a non-significant aging effect and will not impact the intended function of the cranes.

Discussion: The applicant's response is related to the previous RAI concerning same components. Response to previous RAI will determine the acceptability of this response. No further action is needed.

3.3 General

In the definition of reactor coolant, boric acid is not mentioned. Please provide additional description and clarification to the definition of reactor coolant.
Response:

The applicant stated that the definition of reactor coolant provided in LRA Section 3.0 is adequate. Peach Bottom Units 2 and 3 are boiling water reactors. The reactor coolant at Peach Bottom does not contain boric acid.

RAI 3.3.4

Borated water can potentially contain chloride and sulfate impurities, which can cause cracking of stainless steel. Licensee uses SBLC System Surveillance Program to monitor

the conditions of the stainless steel components. Provide description of the criteria for monitoring possible cracking of the structures and components as part of the SBLC (Appendix B, Section 1.13). Since cracking, if any, will likely initiate from internal surface, describe the effectiveness of the Program.

Response:

The applicant stated that as a Boiling Water Reactor (BWR), PBAPS has a standby liquid control (SBLC) system that NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," describes in section VII.E2. GALL describes components of SBLC in contact with a sodium pentaborate solution. The sodium pentaborate solution provides a relatively mild environment whose pH is slightly basic. PBAPS does not have a borated water environment to cause cracking of stainless steel.

Discussion: The applicant's response is acceptable. No further action is needed.

RAI 3.3.5

Table 3.3-5 listed raw water as an environment for HPSW Pump Motor Oil Coolers= cast iron components. However, no aging effect is identified for this environment. Oil systems subject to water contamination are typically subject to the aging effect of loss of material. Identify where in the LRA is the AMR for the aging effect of loss of material from general, pitting, crevice, and microbiologically influenced corrosion (MIC) to cast iron for oil coolers potentially contaminated with leaking water, or provide a justification for excluding this aging effect from Table 3.3-5 and an AMR.

Response:

The applicant stated that Table 3.3-5 does not list raw water as an environment for the HPSW Pump motor oil coolers because it does not exist. The aging effect of loss of material for the cast iron oil coolers of the HPSW pump motors was considered not applicable because the oil environment would not become contaminated with water or contaminants. The HPSW motor lube oil is sampled and analyzed in conjunction with the quarterly pump operability surveillance test. Any water or contaminants in the oil would be identified promptly so that long term aging effects due to loss of material would be eliminated.

Discussion: The applicant's response is acceptable. No further action is needed.

RAI 3.3.6

In section 3.3.5, 3.3.6 and 3.3.14, internal surface of stainless steel, carbon steel and cast iron components are exposed to raw water environment. Typically, the aging effect, fouling, is associated with raw water environments. Explain why fouling is not identified as an applicable aging affect in pipe, pump casings, strainers, and valve bodies in a raw water environment. If it is identified, explain how this environment and the associated aging effect are managed in the LRA.

Response:

The applicant stated that the aging effect of fouling, as it applies to pipe, pump casings, strainers and valve bodies, is called “flow blockage” in the Peach Bottom LRA. Flow blockage is identified as an applicable aging effect in pipe, pump casings, strainers, and valve bodies in a raw water environment. This aging effect is managed by the Generic Letter 89-13 Activity (LRA Appendix B.2.8). In addition, the Inservice Testing (IST) Program (LRA Appendix B.1.11) detects flow blockage in the Emergency Service Water (LRA Section 3.3.6) and Emergency Cooling Water (LRA Section 3.3.14) systems.

Discussion: The applicant’s response is acceptable. The staff will issue a formal RAI.

Subsequent to discussion of information provided by the applicant, the staff plans to issues the following RAIs.

General: HVAC

The following HVAC systems have been identified as being within the scope of license renewal:

Standby Gas Treatment System (section 2.3.2.7)
Control Room Ventilation System (section 2.3.3.8)
Battery and Emergency Switchgear Ventilation System (section 2.3.3.9)
Diesel Generator Building Ventilation System (section 2.3.3.10)
Pump Structure Ventilation System (section 2.3.3.11)

However, no aging effects were identified in Tables 3.2.7, 3.3.8, 3.3.9, 3.3.10, or 3.3.11 for the following component groups in sheltered or ventilation atmosphere environments:

Casting and Forging: Valve Bodies/ Pump Casings
Piping: Pipe, Tubing, Fittings
Piping Specialties: Flow Elements, Nitrogen Electric Vaporizer
Sheet Metal: Ducting, Damper Enclosures, Plenums, Fan Enclosures

Despite the statement in Section B.2.3 that "No physical degradation of metallic ventilation system components has been identified at PBAPS or by industry in general....", metallic HVAC system components at other nuclear power plant facilities have been identified as subject to aging effects. For example, the GALL Report, NUREG-1801 Chapter VII, Item F1-3 cites potential aging mechanisms for HVAC ducts as: Loss of material/General, pitting, crevice corrosion, and microbiologically influenced corrosion (for duct [drip-pan] and piping for moisture drainage). Please explain the basis for determining that no aging effects exist and no aging management activities are required for the systems identified above.

Fire Protection

RAI 3.3.7-1:

Table 3.3-7 identifies black steel pipe and carbon steel pipe used in raw water service in fire protection systems and an aging effect of flow blockage. The design basis of sprinkler systems requires an assumption of a roughness coefficient, a “C” factor in the Hazen-Williams equation. This coefficient declines with age, causing a greater pressure drop and subsequent reduced delivery of water to the suppression system. Changes in the value of this coefficient can be determined by flow tests and used to verify, by calculation, the ability of the system to perform its intended function in terms of flow rate and pressure. Inherent in sprinkler systems are pipe networks which cannot be flow tested. Over an extended time, the interior of the pipe can deteriorate through scaling and tuberculation until the system cannot deliver the required flow with the available pressure. This condition cannot be observed by external visual inspection. Appendix B.2-9 addresses flow testing and visual inspection to monitor and detect blockage. For the piping described above, flow testing is not reasonably achievable. Identify how the internal condition of this piping will be verified to assure flow capability.

RAI 3.3.7-2:

The aging effect of several materials referenced in Table 3.5-14 is listed as Change in Material Properties. Appendix B.2.9 states these changes in material properties will be monitored by visual inspection. Provide the acceptance criteria for required inspection which would identify unacceptable changes in material properties and the bases for these criteria.

RAI 3.3.7-3:

Table 3.3.7 identifies sprinkler heads in four different locations and indicates aging effects as none in one case and three different aging effects in the other listing. It is unclear which heads have no aging effects. Identify by type and plant location which sprinkler heads are considered as having no aging effects. Provide the basis for the conclusion that there are no aging effects.

RAI 3.3.7-4.

In Table 3.3.7 on page 3-77 of the LRA, the applicant does not identify an aging effect for bronze valve bodies in an outdoor environment. The staff requests that the applicant provide information supporting the exclusion of aging effects, such as loss of material, for these components.

3.4 Aging Management of Steam and Power Conversion Systems

RAI 3.4.1-1

Table 3.4-1 Column 5, Aging Effect identified Loss of Material and Cracking as applicable aging effects (this applies also for the other tables listed in the LRA). With respect to those effects please identify the following:

a) Identify where in the LRA the various aging effects listed throughout the application are defined? e.g. What does loss of material means?.

b) Identify the process of identification of aging effects? e.g. Did the applicant identified those effects at random?

c) Was industry and plant specific operating experience considered in the process of identification of aging effects? If so where in the application this review is accounted for?

d) Where in the application the various environments are defined? e.g What does sheltered environment means?.

Response to 3.4.1-1:

The applicant stated the following:

a) Material aging effects are not defined in the LRA. The aging effects terminology is consistent with the terminology used in NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, and in NUREG-1801, Generic Aging Lessons Learned (GALL) Report. The LRA identifies aging effects requiring aging management without identifying the mechanism of the aging effect, in accordance with the requirements of 10 CFR Part 54. For example, loss of material as identified in the LRA is an aging effect requiring aging management that could be due to pitting and crevice corrosion, general corrosion, wear, microbiologically influenced corrosion, etc.

b) Aging effects are identified as part of the aging management review, based on guidance contained in the above referenced documents including consideration of industry and plant specific operating experience. The LRA identifies the appropriate aging effects 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.

c) Aging effects are identified as part of the aging management review, based on guidance contained in the above referenced documents including consideration of industry and plant specific operating experience. In the LRA, the review 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.

d) Environments are defined in LR Section 3.0, under the heading of Environment. As described on page 3-6 of the LRA, the Sheltered environment is defined as:

The applicant further stated that the sheltered environment consists of indoor ambient conditions where components are protected from outdoor moisture. Conditions outside the drywell consist of normal room air temperatures ranging from 65° F - 150° F and a relative humidity ranging from 10% - 90%. The warmest room outside the drywell is the steam tunnel, with an average temperature of 150° F (based on measured temperatures), and maximum normal fluctuation to 165° F.

The drywell is inerted with nitrogen to render the containment atmosphere non-flammable

by maintaining the oxygen content to less than 4% oxygen. The drywell normal operating temperature ranges from 65° F - 150° F with a relative humidity from 10% - 90%.

The sheltered environment atmosphere is an air or nitrogen environment with humidity. Components in systems with external surface temperatures the same or higher than ambient conditions are expected to be dry. Lack of a liquid moisture source in direct contact with a given component precludes the concern of external surface corrosion degradation of metallic components as an effect requiring aging management. Note however that the sheltered environment is considered a corrosive environment for some non-metallic elastomer components.

Discussion: The applicant's response is acceptable. The staff will issue a formal RAI.