tasks without preventing the SSCs from performing their intended safety functions. The reactor building crane is designed to lift and transport spent fuel casks such that no credible postulated failure of any crane component will result in the dropping of a cask. The reactor building cranes also support single-failure-proof criteria for lifting heavy loads over fuel in the reactor pressure vessel or over the spent fuel pool.

The components of the cranes and hoists are described in Section 2.3.3.18 of the LRA as being within the scope of license renewal and subject to aging management review (AMR). The materials of construction of the cranes and hoists are carbon steel, and low-alloy steel. Table 3.3-18 of the LRA lists the individual components of the equipment, including structural members, rails, rail clips, rail bolts, and monorail flanges.

3.3.18.1.1 Aging Effects

The applicant identified carbon and low-alloy steel in outdoor and sheltered environments as susceptible to loss of material.

3.3.18.1.2 Aging Management Programs

The applicant credits Crane Inspection Activities to manage aging effects of the cranes and hoists. This aging management program is described in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components of this system will be adequately managed by these aging management programs so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.3.18.2 Staff Evaluation

The applicant described its AMR of cranes and hoists for license renewal in Section 2.3.3.18 and Table 3.3-18. The staff reviewed this section and table to determine whether the applicant has demonstrated that the effects of aging on the cranes and hoists will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.18.2.1 Aging Effects

By letter dated February 6, 2002, the staff requested additional information per RAI 3.3-3 to justify the exclusion of fatigue and a corresponding TLAA evaluation relating to crane load cycles. By letter dated May 6, 2002, the applicant informed the staff that the LRA was amended to include load cycles for the reactor building overhead bridge cranes, turbine hall cranes, emergency diesel generator bridge cranes, and the circulating water pump structure gentry crane as a TLAA in Section 4.7.4

The staff finds that the applicant's response adequately addresses RAI 3.3-3.

The aging effect of the SSCs in cranes and hoists exposed to the environments the applicant identified in the LRA is consistent with industry experience. The staff finds that the aging effect identified is appropriate.

3.3.18.2.2 Aging Management Programs

Section 2.3.3.18 and Table 3.3-18 of the LRA credit the Crane Inspection Activities with managing aging effects of the cranes and hoists.

The applicant's crane inspection activities are described in Section B.1.14 of the LRA. This program is credited with managing the aging effect of loss of material for the passive components of the cranes and hoists. The staff has reviewed Section B.1.14 of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the crane inspection activities during the extended period of operation as required by 10 CFR 54.21(a)(3).

The crane inspection activities at PBAPS consist of inspections that are relied upon to manage loss of material for passive components of cranes and hoists. These components are identified in Table 3.3-18 of the LRA. They include carbon steel and low-alloy steel structural support components in both outdoor and sheltered environments. The crane inspection activities comply with the requirements of ASME B30.2, B30.11, B30.16, and B30.17, and are implemented through a plant procedure.

The staff's evaluation of the crane inspection activities focused on how the program manages the aging effect through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components that are subject to an aging management review. The applicant's quality assurance program is evaluated separately in Section 3.0.4 of this SER. This program satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining seven elements are discussed below.

Program Scope: Crane inspection activities consist of inspections of the structural members, rails, and rail anchorage for the circulating water pump structure gantry crane located in an outdoor environment, and rails and monorails for the cranes and hoists located in a sheltered environment. The staff finds the program scope appropriate and acceptable because critical components of the cranes and hoists subject to aging management are covered by the inspection activities.

Preventive Actions: Crane inspection activities include inspections to identify component aging effects prior to loss of intended function. No preventive or mitigating attributes are associated with these activities, and the staff did not identify the need for any.

Parameters Monitored or Inspected: The LRA states that crane inspection activities verify structural integrity of crane and hoist elements required to maintain intended functions and comply with ASME B30.1, B30.11, B30.16, and B30.17. By letter dated April 29, 2002, the applicant provided an additional description of the crane inspection activities, noting those activities that are credited for license renewal. The activities include visual inspections for conditions such as corroded structural members, misalignment, flaking, sidewear of rails, loose tiedown bolts, and excessive wear or deformation of the monorail lower flange. The staff finds that visual inspections will detect the aging parameters stated above. The staff also finds that these parameters will adequately verify the structural integrity of the critical crane and hoist elements and are, therefore, acceptable.

Detection of Aging Effects: Crane inspection activities provide for inspections to identify deficiencies in components and degradation due to loss of material. The staff finds visual inspections to be an effective means of detecting the aging effect of concern and, therefore, finds visual inspections acceptable.

Monitoring and Trending: Crane inspection activities monitor inspection results from previously identified findings and for newly emerging conditions. The annual inspections provide for prediction of the onset of degradation and for timely implementation of corrective actions to prevent loss of intended function. The staff finds that the monitoring and trending of inspection results on an annual basis will identify degradation prior to structural failure and are, therefore, acceptable.

Acceptance Criteria: Crane inspection activities provide for engineering evaluation of inspection results to assess the ability of the crane or hoist to perform its intended function. The acceptance criterion is no unacceptable visual indication of loss of material due to corrosion or wear. The loss of material due to corrosion or wear of the critical crane and hoist elements can be identified based on visual inspections such that there is still a substantial margin to failure available. Therefore, the staff finds the acceptance criterion acceptable.

Operating Experience: No incidents of failure of passive crane and hoist components due to aging have occurred at PBAPS. Loss of material in crane rails and monorails has been detected and managed by the crane inspection activities. Therefore, the staff finds that there is reasonable assurance that the intended functions of crane and hoist passive components will be maintained during the period of extended operation.

The staff reviewed Section A.1.14 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

On the basis of its review, as discussed above, the staff concludes that the applicant has demonstrated that the crane and inspection activities will adequately manage the aging effects associated with the crane and hoist components for the period of extended operation as required by 10 CFR 54.21 (a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.3.18.2.3 Conclusions

The staff has reviewed the information in Sections 2.3.3.18 and 3.3.18 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effect associated with cranes and hoists will be adequately managed so that there is reasonable assurance that this system will perform its intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4 Aging Management of Steam and Power Conversion Systems

The applicant described its AMR of the steam and power conversion systems for license renewal in LRA Sections 2.3.4, "Steam and Power Conversion Systems," and 3.4, "Aging Management of Steam and Power Conversion Systems." The staff has reviewed this section and tables 3.4-1 thru 3.4-3 of the application to determine whether the applicant has provided adequate information to meet the requirements of 10 CFR 54.21(a)(3) for managing the aging effects of the steam and power conversion systems for license renewal.

The LRA identified three systems that will require aging management to meet the requirements of 10 CFR 54.21(a)(3) for management of aging effects. The three systems are the main steam system, main condenser, and feedwater system. The LRA included a summary of the results of the aging management review for these three systems. The results are listed in Tables 3.4-1 through 3.4-3 of the LRA. The tables provide the following information: (1) component groups, (2) component intended functions, (3) environments , (4) materials of construction, (5) aging effects, and (6) aging management activities that manage the identified aging effects.

Section 3.0 of the LRA identified seven environments that are applicable to the steam and power conversion systems:

- Reactor coolant: Reactor coolant system water is demineralized and maintained in accordance with stringent chemistry parameters to mitigate corrosion.

- Steam: Steam is produced in the reactor vessel from reactor-grade water and has extremely low levels of impurities. The systems that are pertinent to this evaluation are the reactor pressure vessel and internals, main steam, HPCI, and RCIC systems. The steam exists as a two-phase vapor, ranging from high-quality steam in the main steam system to low-quality steam in the HPCI and RCIC systems. The HPCI and RCIC steam lines normally see little to no steam flow because these systems operate infrequently.

- Torus-Grade Water: The torus-grade water quality is monitored periodically and maintained in accordance with station procedures that include recommendations from EPRI TR-103515, "BWR Water Chemistry Guidelines." Purity of the torus water is maintained by pumping the torus water through filters and demineralizers and by bleed and feed operations with the hotwell. Some carbon steel pipes in the torus pass through the surface of the torus water and are exposed to a water-gas interface. For lines equipped with vacuum breaker valves, the water-gas interface occurs at both the inside and outside diameter of the pipe. For other lines, a water-gas interface occurs only at the outside diameter because the inside of the pipe remains full of water.

- Raw Water: Raw water is untreated fresh water taken from Conowingo Pond, which is formed by the Susquehanna River. Raw water typically contains a dilute solution of mineral salt impurities, dissolved gases, and biological organisms. These dissolved gases (oxygen and carbon dioxide) are the prime corrosion-initiating agents. Water samples show pH variation from 7.00 to 7.55, chloride content of 9 to 18 ppm, and sulfate content from 1 to 46 ppm.

- Sheltered: 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 to 150 °F and a relative humidity ranging from 10% to 90%. The warmest room outside the drywell is the steam tunnel, with an average temperature of 150 °F (based on measured temperatures) and a maximum normal fluctuation to 165 °F. The drywell is inerted with nitrogen to render the containment atmosphere nonflammable by maintaining the oxygen content less than 4% oxygen. The drywell normal operating temperature ranges from 65 °F to 150 °F with a relative humidity from 10% to 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 external surface corrosion of metallic components as an effect requiring aging management.

- Wetted Gas: Wetted gas environments include air, containment atmosphere, and diesel exhaust gas. Air is either ambient or compressed air without air dryers in the system. Containment atmosphere in the drywell and torus is inerted with nitrogen with only 4% oxygen but is assumed to have the same corrosive effects as ambient air. Diesel exhaust can contain sulfur residues so exhaust system components can be exposed to moisture and sulfuric acid.

- Dry Gas: The dry gas environments include dried air, nitrogen, carbon dioxide, hydrogen, oxygen, and freon. These gases are considered inert with respect to corrosion because they have no significant moisture content.

To provide reasonable assurance that the aging effects that require management for a specific material-environment combination are the only aging effects of concern for Peach Bottom, the applicant also performed a review of industry experience and NRC generic communications relative to the engineered safety features structures and components. In addition, relevant Peach Bottom operating experience was reviewed to provide additional confidence that all aging effects for the specific material-environment combinations have been identified.

3.4.1 Main Steam System

3.4.1.1 Technical Information in the Application

The Peach Bottom main steam system conducts steam from the reactor vessel through the primary containment to the steam turbine over the full range of reactor power operation. Four steam lines are utilized between the reactor and the main turbine. The use of multiple lines permits turbine stop valve and main steam line isolation valve testing during plant operation with a minimum amount of load reduction.

3.4.1.1.1 Aging Effects

Table 3.4-1 of the LRA identified the following components that will require aging management during the extended period of operation: piping, pipe specialties (flow elements, dashpot, Y strainer, condensing chambers, spargers, restricting orifices, flexible hoses), tubing, accumulators, and valve bodies. The applicant identified stainless steel, carbon steel, copper, and brass as the materials of construction for the main steam components.

3.4.1.1.2 Aging Management Programs

The LRA identified five aging management programs to manage the aging effects in the main steam system during the extended period of operation. These five programs are:

- RCS Chemistry Program
- ISI Program
- Torus Piping Inspection Program
- FAC Program
- Torus Water Chemistry Program

3.4.1.2 Staff Evaluation

The staff reviewed the information included in Section 3.4 of the LRA. The purpose of the review was to ascertain whether the applicant has adequately demonstrated that the effects of aging associated with the main steam system will be adequately managed so that the intended function of the system will be maintained consistent with the CLB throughout the period of extended operation in accordance with 10 CFR 54.21(a)(3).

3.4.1.2.1 Aging Effects

The LRA included a summary of the results of the aging management review for the main steam system. The results are listed in Table 3.4-1 of the LRA. The materials of construction, applicable environments, and aging effects for the main steam system are as follows:

- stainless steel, carbon steel, brass and copper in dry gas and sheltered environments—no aging effects
- carbon steel in a steam environment— loss of material
- stainless steel in a steam environment—loss of material and cracking
- carbon steal in a wetted gas environment—loss of materials
- stainless steel in a wetted gas environment—cracking
- carbon steel in a torus-grade water environment—loss of material

No aging effects were identified in the AMR of piping, piping specialties, accumulators, tubing, and valve bodies made of stainless steel, carbon steel, brass or copper in a dry gas or sheltered environment. These materials are resistant to corrosion in both dry gas and sheltered environments. The applicant, therefore, has not identified any applicable aging effects for the surfaces of stainless steel, carbon steel, brass, or copper main steam system components exposed to these environments.

Loss of material was identified for carbon steel piping, piping specialties, and valve bodies in steam environments. Loss of material of carbon steel materials by corrosion may occur in steam environment, and therefore may be an applicable aging effect for carbon steel surfaces exposed to steam. The applicant will use the RCS chemistry program, ISI program, and FAC program to manage loss of material for carbon steel piping, piping specialties, and valve bodies in a steam environment.

Loss of material and cracking were identified for the stainless steel piping, piping specialties, and tubing in steam environments. Loss of material and cracking of stainless steel materials may occur in steam environment, and therefore may be an applicable aging effect for stainless steel surfaces exposed to steam. The applicant will use the RCS chemistry program and ISI program to manage loss of material for stainless steel piping, piping specialties, and tubing in a steam environment.

Loss of material was identified for the carbon steel piping, and valve bodies in wetted gas environments. Loss of material of carbon steel materials by corrosion may occur in a wetted gas environment, and therefore may be an applicable aging effect for carbon steel surfaces exposed to wet gas. The applicant will use the ISI program and Torus Piping Inspection program to manage loss of material for carbon steel piping and valve bodies in a wetted gas environment.

Cracking of material was identified for the stainless steel piping, piping specialties, and valve bodies in wetted gas environments. Cracking of stainless steel materials may occur in a wetted gas environment, and therefore may be an applicable aging effect for stainless steel surfaces exposed to wet gas. The applicant will use the ISI program to manage cracking associated with stainless steel piping, piping specialties, and valve bodies in wetted gas environment.

Loss of material was identified for carbon steel piping and piping specialties in a torus-grade water environment. Loss of material of carbon steel materials by corrosion may occur in torus-grade water environment, and therefore may be an applicable aging effect for carbon steel surfaces exposed to torus water. The applicant will use the Torus Water Chemistry program and Torus Piping Inspection program to manage loss of material for carbon steel piping and piping specialties in a torus-grade water environment.

3.4.1.2.2 Aging Management Programs

The applicant stated that the RCS chemistry program, ISI program, and FAC program will be used to manage the loss of material associated with carbon steel piping, piping specialties, and valve bodies in a steam environment. The RCS chemistry program and ISI program will be used to manage the loss of material associated with stainless steel piping, piping specialties, and tubing in a steam environment. The ISI program and Torus Piping Inspection program will be used to manage the loss of material associated with carbon steel pipe, and valve bodies in a wetted gas environment. The ISI program will be used to manage cracking associated with stainless steel pipe, pipe specialties, and valve bodies in a wetted gas environment. The Torus Water Chemistry program and Torus Piping Inspection program will be used to manage the loss of material associated with carbon steel piping and piping specialties in a torus-grade water environment. Detailed description concerning each of the programs identified above is included in Appendix B to the LRA, along with a demonstration that the identified aging effects will be effectively managed for the period of extended operation. The staff's detailed review of the different aging management activities and their ability to adequately manage the applicable aging effects is provided in Sections 3.0.3.1, 3.0.3.2, and 3.0.3.6 of this SER. As a result of this review, the staff did not identify any concerns or omissions in the aging management activities used to manage the main steam system.

3.4.1.3 Conclusions

The staff has reviewed the information in Section 3.4, "Aging Management of Steam and Power Conversion Systems," of the LRA. On the basis of its review, the staff concludes that the applicant's identification of the aging effects associated with the main steam system is consistent with published literature and industry experience. The staff further concludes that the applicant has adequate aging management programs to effectively manage the aging effects of the main steam system and that there is reasonable assurance that the intended functions of the system will remain consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.2 Main Condenser

3.4.2.1 Technical Information in the Application

The Peach Bottom main condenser provides a heat sink for the turbine exhaust steam and turbine bypass steam. It also deaerates and stores the condensate for reuse after a period of radioactive decay. Additionally, the main condenser provides for post-accident containment, holdup, and plateout of main steam isolation valve (MSIV) bypass leakage.

The main condenser is a single-pass, single-pressure, deaerating type with a reheating deaerating hotwell and divided waterboxes. The condenser consists of three sections, each located below the low-pressure elements of the turbine, with the tubes oriented transverse to the turbine-generator axis. The steam exhausts directly down into the condenser shells through exhaust openings in the bottom of each low-pressure turbine casing. The condensers also receive steam from the reactor feed pump turbines.

3.4.2.1.1 Aging Effects

Table 3.4-2 of the LRA identified the following components of the main condenser as subject to AMR: main condenser shell, tubesheet, tubes, waterbox, feedwater heater shell, drain cooler shell, nozzles, and expansion joints. No aging effects requiring aging management during the period of extended operation were identified for these components. The applicant identified stainless steel, carbon steel, and titanium as the materials of construction for the main condenser components.

3.4.2.1.2 Aging Management Programs

The LRA identified no aging management programs to manage the aging effects for the main condenser during the extended period of operation.

3.4.2.2 Staff Evaluation

The staff has reviewed the information included in Section 3.4 of the LRA. The purpose of the review was to ascertain whether the applicant has adequately demonstrated that the effects of aging associated with the main condenser will be adequately managed so that the intended function of the main condenser will be maintained consistent with the CLB throughout the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.2.2.1 Aging Effects

The LRA included a summary of the results of the aging management review for the main condenser. The results are listed in Table 3.4-2 of the LRA. The materials of construction, applicable environments and aging effects for the main condenser are as follows:

- carbon and stainless steel in a steam environment—no aging effects
- carbon steel in reactor coolant and raw water environments—no aging effects
- titanium tubes in steam and raw water environments—no aging effects

No aging effects were identified by the AMR for the main condenser components made of carbon steel, stainless steel, or titanium in steam, reactor coolant, or raw water environments. These materials have successfully performed as main condenser materials at other plants. Further, the applicant has concluded that aging management of the main condenser is not required based on analysis of materials, environments, and aging effects. Condenser integrity required to perform the post-accident intended function (holdup and plateout of MSIV leakage) is continuously confirmed by normal plant operation. The main condenser must perform a significant pressure boundary function (maintain vacuum) to allow continued plant operation. For these reasons, the applicant has not identified any applicable aging effects for the main condenser. The staff concurs with the applicant's conclusion because the main condenser integrity is continuously confirmed during normal plant operation and thus the condenser post-accident function will be ensured.

3.4.2.2.2 Aging Management Programs

The applicant did not identify any management programs to manage aging effects for the main condenser materials because no aging effects were identified as applicable to the main condenser. The above-identified main condenser materials have successfully performed as main condenser materials at other plants with no problems being reported. Further, the applicant has concluded that the main condenser must perform a significant pressure boundary function (maintain vacuum) to allow continued plant operation. The staff concurs with the applicant's conclusion that the main condenser does not require aging management because the main condenser integrity is continuously tested and confirmed during normal plant operation.

3.4.2.3 Conclusions

The staff has reviewed the information in Section 3.4, "Aging Management of Steam and Power Conversion Systems," of the LRA. On the basis of its review, the staff concludes that the applicant's assessment of the aging effects associated with the main condenser is consistent with published literature and industry experience. The staff further concludes that the applicant does not need aging management programs to manage the aging effects because the main condenser integrity is continuously confirmed during normal plant operation and thus the condenser post-accident function will be ensured consistent with the CLB throughout the extended period of operations.

3.4.3 Feedwater System

3.4.3.1 Technical Information in the Application

The Peach Bottom feedwater system receives its supply of water from the outlet of the condensate demineralizers during normal plant operation. The system consists of three feedwater heater strings (with cascading drains) connected in parallel, each consisting of five low-pressure feedwater heaters and one drain cooler in series. The feedwater heaters receive steam from the main turbine system and preheat feedwater before it enters the reactor feed pumps, thus increasing the heat cycle efficiency.

3.4.3.1.1 Aging Effects

Table 3.4-3 of the LRA identified the following components as requiring aging management during the extended period of operation: piping, piping specialties, tubing, and valve bodies. The applicant identified carbon, low alloy, and stainless steel as the materials of construction for the feedwater components.

3.4.3.1.2 Aging Management Programs

The LRA identified three aging management programs that will manage the aging effects on the main steam system during the extended period of operation:

- RCS Chemistry Program
- ISI Program
- FAC Program

3.4.3.2 Staff Evaluation

The staff has reviewed the information included in Section 3.4 of the LRA and the changes to the LRA as supplemented in a letter from M.P. Gallagher to NRC dated December 19, 2002. The purpose of the review was to ascertain whether the applicant has adequately demonstrated that the effects of aging associated with the feedwater system will be adequately managed so that the intended function of the system will be maintained consistent with the CLB throughout the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.3.2.1 Aging Effects

The LRA included a summary of the results of the aging management review for the feedwater system. The results are listed in Table 3.4-3 of the LRA. The materials of construction, applicable environments, and aging effects for the feedwater system are as follows:

- carbon, low alloy, and stainless steel in a sheltered environment—no aging effects
- carbon and low alloy steel and stainless in a reactor coolant environment—loss of material
- stainless steel in a reactor coolant environment—cracking
- low allow steel in a reactor coolant environment—loss of material

No aging effects were identified by the AMR for piping, piping specialties, tubing, and valve bodies made of stainless steel, low alloy steel or carbon steel in a sheltered environment. These materials are corrosion resistant in sheltered environments. The applicant, therefore, has not identified any applicable aging effects for the surfaces of stainless steel, low alloy steel or carbon steel feedwater system components exposed to this environment.

Loss of material was identified for the carbon and stainless steel or low alloy steel piping, piping specialties, and valve bodies in a reactor coolant environment. Loss of material of carbon and stainless steel or low allow steel by corrosion may occur in reactor coolant environment, and therefore may be an applicable aging effect for the carbon steel or low alloy steel surfaces exposed to reactor coolant water. The applicant will use the RCS chemistry program, ISI program, and FAC program to manage loss of material for carbon steel piping, piping specialties, and valve bodies. The applicant will use the RCS chemistry program to manage loss of material for stainless steel or low alloy steel piping (tubing) and valve bodies.

Cracking was identified for the stainless steel pipe, tubing, and valve bodies in a reactor coolant environment. Cracking of stainless steel materials may occur in reactor coolant environment, and therefore may be an applicable aging effect for the stainless steel surfaces exposed to reactor coolant. The applicant will use the RCS chemistry program to manage the cracking associated with stainless steel pipe, tubing, and valve bodies in a reactor coolant environment.

3.4.3.2.2 Aging Management Programs

The applicant stated that the RCS chemistry program, ISI program, and FAC program will be used to manage the loss of material associated with carbon steel or low alloy steel piping, piping specialties, and valve bodies. The RCS chemistry program will be used to manage the cracking associated with stainless steel pipe, tubing, and valve bodies in a reactor coolant environment.

A detailed description of each of the programs identified above is included in Appendix B to the LRA, along with a demonstration that the identified aging effects will be effectively managed for the period of extended operation. The staff's detailed review of the different aging management activities and their ability to adequately manage the applicable aging effects is provided in Sections 3.0.3.1, 3.0.3.2, and 3.0.3.6 of this SER. As a result of its review, the staff did not identify any concerns or omissions in the aging management activities used to manage the feedwater system.

3.4.3.3 Conclusions

The staff has reviewed the information in Section 3.4, "Aging Management of Steam and Power Conversion Systems," of the LRA. The staff considered both industry and plant-specific experience. On the basis of its review, the staff concludes that the applicant's identification of the aging effects associated with the feedwater system is consistent with published literature and industry experience. The staff further concludes that the applicant has adequate aging management programs to effectively manage the aging effects of the feedwater system and that there is reasonable assurance that the intended functions of the system will remain consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5 Aging Management of Structures and Component Supports

3.5.1 Containment Structure

3.5.1.1 Technical Information in the Application

The aging management review results for the containment structure, which consists of the primary containment of each unit and internal structural steel, are presented in Table 3.5-1 of the LRA. Table 3.5-1 of the LRA identifies the components of the containment structure along with their (1) intended functions, (2) environments, (3) materials, (4) aging effects, and (5) aging management activities.

Section 2.4.1 of the LRA states that the containment structure consists of the primary containment of each unit and internal structural steel. The primary containment of each unit is of the Mark I design and consists of a drywell, a suppression chamber in the shape of a torus, and a connecting vent system between the drywell and suppression chamber. The containment structure is also an enclosure for the reactor vessel, the reactor coolant recirculation system, and other branch connections of the reactor coolant system. The drywell is a steel pressure vessel in the shape of a light bulb, and is enclosed in reinforced concrete for shielding purposes. The pressure suppression chamber is a torus-shaped steel pressure vessel located below and encircling the drywell. It contains approximately 125,000 cu ft of water and has a gas space volume above the pool. The pressure suppression chamber is supported on braced vertical columns to carry its loading to the reinforced concrete foundation slab of the reactor building. Internal structural steel is used at various elevations of the drywell and suppression chamber to provide structural support to safety-related and non-safety-related systems and equipment inside the drywell.

The materials of construction for the containment structure, as shown in Table 3.5-1 of the LRA, are concrete, carbon steel, stainless steel, elastomers, bronze, and graphite. The pressure suppression chamber gaskets and drywell gaskets are made of ethylene propylene dienyl monomer (EPDM).

The containment structure components are exposed to an internal or sheltered environment and some vent system and pressure suppression chamber components are exposed to torus water.

3.5.1.1.1 Aging Effects

Table 3.5-1 of the LRA identifies the following applicable aging effects for components in the containment structure:

- loss of material of carbon and stainless steel components in sheltered or torus water environments
- cumulative fatigue damage of carbon and stainless steel components in sheltered or torus water environments
- change in material properties and cracking of elastomers in a sheltered environment

The applicant did not identify loss of material or cumulative fatigue damage for all of the carbon steel components in the containment structure; however, either one or both of these aging effects are identified for all in-scope stainless steel components in the containment structure.

3.5.1.1.2 Aging Management Programs

Table 3.5-1 of the LRA credits the following two aging management activities with managing the identified aging effects for the components in the containment structure:

- Primary Containment ISI Program
- Primary Containment Leakage Rate Testing Program

A description of these two aging management activities is provided in Appendix B of the LRA. For the cumulative fatigue damage aging effect for steel components in the containment structure, the applicant credits various time-limited aging analyses (TLAAs), which are described in Section 4 of the LRA. The applicant concludes that the effects of aging associated with the components in the containment structure will be adequately managed by these aging management activities such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.1.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports" and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the containment components have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for the aging effects and the applicant's programs credited for the aging management of the containment at each Peach Bottom unit. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the containment components.

3.5.1.2.1 Aging Effects

Concrete: No aging effects are identified in Table 3.5-1 for the concrete containment components. These concrete containment components are the (1) reinforced concrete reactor pedestal, foundation, and floor slab and (2) the unreinforced concrete sacrificial shield wall. All of these concrete containment components are exposed to a sheltered environment.

The staff considers cracking, change in material properties, and loss of material to be applicable aging effects for concrete containment components that are exposed to sheltered or outdoor environments. The NRC staff position regarding the aging management of in-scope concrete structures and components (SCs) is that they need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. Concrete SCs in nuclear power plants are prone to various types of age-related degradation, depending on the stresses and strains due to normal and incidental loadings and the environment to which they are subjected. Concrete SCs subjected to sustained loading, such as crane or monorail operation, and/or sustained adverse environmental conditions, such as high temperatures, humidity, or chlorides, will degrade, thereby potentially affecting the intended functions of the SCs. These degradations to concrete SCs are manifested through aging effects such as cracking, loss of material, and change in material properties. As concrete SCs age, such aging effects accentuate. On the basis of industry-wide evidence, the American Concrete Institute (ACI) has published a number of documents (e.g., ACI 201.1R, "Guide for Making a Condition Survey of

Concrete," ACI 224.1R, "Causes, Evaluation and Repairs of Cracks in Concrete Structures," and ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures") that identify the need to manage the aging of concrete structures. These reports and standards confirm the inherent tendency of concrete structures to degrade over time if not properly managed. Similar observations of concrete aging made by NRC staff are detailed in NUREG-1522, "Assessment of In-Service Conditions of Safety-Related Nuclear Power Plant Structures." Accordingly, in RAI 3.5-1 the staff requested that the applicant identify the aging management program(s) that will be used to manage the aging effects for the concrete containment components listed in Table 3.5-1 of the LRA.

In response, the applicant stated:

> PBAPS aging management reviews (AMRs) concluded that concrete and block wall aging effects are non-significant, will not result in a loss of intended function, and thus require no aging management. The AMRs are based on guidelines for implementing the requirements of 10 CFR Part 54, developed jointly by the NRC and the industry, that are documented in NEI 95-10. The AMR results are also confirmed by PBAPS operating experience.
>
> Exelon therefore is not in agreement with the staff's position, that PBAPS concrete and block wall aging effects require aging management. However, we recognize that, contrary to our experience, the staff is concerned that unless concrete and block wall aging effects are monitored they may lead to a loss of intended function. As a result, we will monitor concrete and block wall structures in accessible areas, for loss of material, cracking and change in material properties. The PBAPS Maintenance Rule Structural Monitoring Program (B.1.16) will be used to monitor the structures.

The applicant's commitment to monitor concrete and block wall aging effects in accessible areas is acceptable to the staff. The applicant has decided to use the Maintenance Rule Structural Monitoring Program to manage concrete aging. This program is reviewed in Section 3.0.3.11 of this SER.

For inaccessible concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the inaccessible soil/groundwater environment is nonaggressive. In response to RAI 3.5-1, the applicant provided water chemistry results that show that the Peach Bottom soil/groundwater environment is nonaggressive (pH = 7.2, sulfates = 38 ppm, and chlorides = 24 ppm). Consequently, the applicant concluded that the aging management of below-grade concrete is not required. Since the groundwater chemistry at the Peach Bottom site is well above the limit for pH (5.5) and below the limits for sulfates (1500 ppm) and chlorides (500 ppm), the staff concurs with the applicant's conclusion that the groundwater is nonaggressive with respect to concrete. Therefore, below-grade concrete does not need to be managed by the applicant.

The staff considers the applicant's response to RAI 3.5-1 to be adequate with respect to managing the aging of concrete and masonry block walls during the period of extended operation.

Steel: The applicant identified (1) loss of material of carbon and stainless steel components in sheltered or torus water environments and (2) cumulative fatigue damage of carbon and stainless steel components in sheltered or torus water environments as applicable aging effects for steel components in the containment structure.

The staff concurs with the aging effects identified above by the applicant for the carbon steel and stainless steel components in the containment structure. However, the staff noted in Part 1 of RAI 3.5-2, that no aging effects are identified in Table 3.5-1 for the carbon steel structural supports, pipe whip restraints, missile barriers, and radiation shields in the containment structure. In response to Part 1 of RAI 3.5-2, the applicant stated:

> PBAPS aging management reviews (AMRs) concluded that carbon steel exposed to a sheltered environment would be subjected to non-significant loss of material due to atmospheric corrosion. The estimated reduction in material thickness will not significantly degrade the load bearing capacity of structural members and thus will not adversely impact their intended function. The AMRs are based on guidelines for implementing the requirements of 10 CFR Part 54, developed jointly by the NRC and the industry, and are documented in NEI 95-10. The AMR results are also confirmed by PBAPS operating experience.
>
> 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 PBAPS operating experience. The position and its justification were discussed with NRC staff on January 28, 2002 in a telephone call. The staff indicated that it does not agree with the Exelon position and an aging management activity is required to ensure the intended function is maintained through the extended term of operation. As a result, Exelon will monitor carbon steel components in a sheltered environment as described below.
>
> - Containment Structure (Table 3.5-1). Carbon steel components in accessible areas inside containment (i.e. structural supports, pipe whip restraints, missile barriers, and radiation shields) will be monitored for loss of material due to corrosion. The PBAPS Maintenance Rule Structural Monitoring Program (B.1.16) will be used for structural steel components other than Class MC component supports. Class MC component supports will be monitored using the Primary Containment ISI Program (B.1.9).

The applicant's commitment to monitor carbon steel components inside containment for loss of material is acceptable to the staff. The applicant has decided to use the Maintenance Rule Structural Monitoring Program to manage structural steel components other than Class MC component supports. For Class MC component supports, the applicant has committed to using the Primary Containment ISI Program. The staff considers Part 1 of RAI 3.5-2 to be closed.

Elastomers (seals, gaskets, O-rings): Table 3.5-1 of the LRA identifies cracking and change in material properties as aging effects for the elastomer components in the containment structure. The staff concurs with the applicant's identification of these two aging effects for elastomers associated with the primary containment pressure boundary components.

Bronze/Graphite: Table 3.5-1 of the LRA does not identify any aging effects for the bronze/graphite Lubrite plates in the containment structure. In Part 1 of RAI 3.5-3, the staff requested further information regarding the applicant's AMR for Lubrite plates. In response, the applicant stated:

> Lubrite is the trade name for a low-friction lubricant material used in applications where relative motion (sliding) is desired. At PBAPS, lubrite plates are incorporated in the design of limited component supports to reduce or release horizontal loads due to temperature transients and SRV discharges.
>
> PBAPS AMRs determined that there are no known aging effects for the lubrite material that would lead to a loss of intended function. As explained by previous applicants and concurred by the staff, lubrite resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high intensities of radiation, and will not score or mar. In addition, lubrite products are solid, permanent, completely self-lubricating, and require no maintenance as documented in NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4." A search of PBAPS and industry operating experience found no reported instances of lubrite plate degradation or failure to perform their intended function. On this basis, Exelon maintains that lubrite plates require no aging management.

The staff concurs with the applicant's response to RAI 3.5-3 with respect to the need for managing the aging of lubrite plates. The applicant's AMR of lubrite material is consistent with industry experience. The staff considers Part 1 of RAI 3.5-3 to be closed.

3.5.1.2.2 Aging Management Programs

Table 3.5-1 of the LRA credits the following aging management programs with managing the identified aging effects for the components in the containment structure:

- Primary Containment ISI Program
- Primary Containment Leakage Rate Testing Program

In addition, in response to RAIs 3.5-1 and 3.5-2 the applicant has committed to using the Maintenance Rule Structural Monitoring Program to manage the aging effects for several additional concrete and structural steel components in the containment structure. The Maintenance Rule Structural Monitoring Program, Primary Containment ISI Program, and Primary Containment Leakage Rate Testing Program are credited with managing the aging of several components in several different structures and systems and are, therefore, considered common aging management programs. The adequacy of seals and gaskets associated with the primary containment pressure boundary is assessed under the primary containment leakage rate testing program in SER Section 3.0.3.8. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.1.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the containment structure will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.2 Reactor Building Structure

3.5.2.1 Technical Information in the Application

The aging management review results for the reactor building structure are presented in Table 3.5-2 of the LRA. Table 3.5-2 of the LRA identifies the components that constitute the reactor building structure along with their (1) intended functions, (2) environments, (3) materials of construction, (4) aging effects, and (5) aging management activities.

Section 2.4.2 of the LRA states that the reactor building for each unit is a seismic Class I structure completely enclosing the primary containment and auxiliary systems of the nuclear steam supply system and housing the associated spent fuel storage pool, dryer and separator storage pool, and reactor well. The building is a reinforced concrete structure from its foundation floor to its refueling floor. Above this floor, the building superstructure consists of metal siding and roof decking supported on structural steel framework. The foundation of the building consists of a reinforced concrete mat supported on rock. This mat also supports the primary containment and its internals, including the reactor vessel pedestal. The exterior and some interior walls of the building above the foundation are cast-in-place concrete. Other interior walls are normal weight concrete block walls. Floor slabs of the buildings are of composite construction with cast-in-place concrete over structural steel beams and metal floor deck. The thickness of walls and slabs was governed by structural requirements or shielding requirements. The steel-framed superstructure is cross-braced to withstand wind and earthquake forces and supports metal siding, metal roof deck, and roofing. The frame also supports a runway for the 125-ton traveling reactor building crane.

The materials of construction for the reactor building structure, as shown in Table 3.5-2 of the LRA, are concrete, masonry block, carbon steel, stainless steel, and aluminum. Boraflex is used for Boraflex absorbers.

The reactor building structure components are exposed to buried, outdoor, sheltered, and fuel pool water environments.

3.5.2.1.1 Aging Effects

Table 3.5-2 of the LRA identifies the following applicable aging effects for components in the reactor building structure:

- loss of material of carbon steel components in an outdoor environment
- loss of material of stainless steel components in a fuel pool water environment
- loss of material of aluminum components in a fuel pool water environment
- change in material properties of Boraflex in a fuel pool water environment

3.5.2.1.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following aging management activities with managing the identified aging effects for the components in the reactor building structure:

- Fuel Pool Chemistry program
- Maintenance Rule Structural Monitoring Program
- Boraflex Management Activities program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in the reactor building structure will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.2.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports," and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the reactor building structure components have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for the aging effects and the applicant's programs credited for the aging management of the reactor building structure at each Peach Bottom unit. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the reactor building components.

3.5.2.2.1 Aging Effects

Concrete: The applicant did not identify any applicable aging effects for the reinforced concrete walls, slabs, columns, beams, and foundation that make up the reactor building structure. In addition, the applicant did not identify any aging effects for the reinforced concrete block walls within the reactor building structure.

As noted above in Section 3.5.1.2.1 of this SER, the staff considers loss of material, cracking, and change in material properties to be both plausible and applicable aging effects for all concrete components, including masonry block walls, in all of the environments listed by the applicant. The NRC staff position regarding the aging management of in-scope concrete structures and components (SCs) is that they need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. In RAI 3.5-1, the staff requested further information regarding the applicant's AMR of concrete components and specifically, the applicant's determination that management of concrete aging is not required. In response to RAI 3.5-1, the applicant stated that it is not in agreement with the staff's position regarding the aging management of concrete structures; however, the applicant has decided that it will manage concrete and masonry block wall aging during the period of extended operation. The applicant specifically stated that it will monitor concrete and masonry block wall structures for loss of material, cracking, and change in material properties through the Maintenance Rule Structural Monitoring Program. Since this commitment from the applicant covers the outdoor and sheltered reactor building structure concrete components, this response is considered acceptable by the staff. RAI 3.5-1 is considered closed with respect to the outdoor and sheltered reactor building concrete components.

For the inaccessible reactor building concrete components, the staff has determined that aging management is unnecessary if applicants are able to show that the soil/groundwater environment is nonaggressive. In response to RAI 3.5-1, the applicant provided water chemistry results that show that the Peach Bottom soil/groundwater environment is nonaggressive (pH = 7.2, sulfates = 38 ppm, and chlorides = 24 ppm). Consequently, the applicant concluded that the aging management of concrete in inaccessible areas is not required. Since the groundwater chemistry at the Peach Bottom site is well above the limit for pH (5.5) and below the limits for sulfates (1500 ppm) and chlorides (500 ppm), the staff concurs with the applicant's conclusion that the groundwater is nonaggressive with respect to concrete. Therefore, concrete in inaccessible areas does not need to be managed by the applicant.

Steel: The applicant identified (1) loss of material of carbon steel components in an outdoor environment and (2) loss of material of stainless steel components in a fuel pool water environment as applicable aging effects for steel components in the reactor building structure.

The staff concurs with the aging effects identified above by the applicant for the carbon steel and stainless steel components in the reactor building structure. However, the staff noted in Part 2 of RAI 3.5-2, that no aging effects are identified in Table 3.5-2 for the carbon steel components in a sheltered environment within the reactor building structure. In response to Part 2 of RAI 3.5-2, the applicant stated that it disagrees with the staff's position that carbon steel components in a sheltered environment require aging management. However, in response to RAI 3.5-2, the applicant committed to monitor carbon steel components in a sheltered environment for loss of material. Included in this commitment are all of the carbon steel components in the reactor building exposed to a sheltered environment for which the applicant did not originally identify any aging effects. Therefore, the staff considers the applicant's response to RAI 3.5-2 to be adequate.

Aluminum: Table 3.5-2 of the LRA identifies loss of material as an applicable aging effect for the aluminum fuel pool gates and component supports. For the portion of the aluminum fuel pool gates in a sheltered environment (above the fuel pool water level), the applicant did not identify any aging effects. The staff concludes that the applicant has properly identified the applicable aging effect for the aluminum components in the reactor building structure that are exposed to fuel pool water.

Boraflex: Table 3.5-2 of the LRA identifies change in material properties for the Boraflex absorbers in the fuel pool as an applicable aging effect. The staff concurs with the applicant's identification of change in material properties as an applicable aging effect for the Boraflex absorbers in the fuel pool. To manage the aging of the Boraflex absorbers, the applicant has proposed to use the Boraflex Management Activities aging management program.

3.5.2.2.2 Aging Management Programs

Table 3.5-2 of the LRA credits the following aging management activities with managing the identified aging effects for the components in the reactor building structure:

- Fuel Pool Chemistry
- Maintenance Rule Structural Monitoring Program
- Boraflex Management Activities

The Maintenance Rule Structural Monitoring Program is credited with managing the aging of several components in several different structures and systems and is, therefore, considered a common aging management program. The staff review of the common aging management programs is in Section 3.0 of this SER. The staff evaluations of the Fuel Pool Chemistry and the Boraflex Management Activities programs are given below.

Boraflex Management Activities Program

Boraflex Management Activities

The applicant described the Boraflex management activities AMP in Section B.2.2 of Appendix B of the LRA. The staff reviewed the applicant's description of the AMP in Section B.2.2 of the LRA to determine whether the applicant has demonstrated that the Boraflex management activities AMP will adequately manage the effects of aging of the spent fuel rack neutron poison material during the period of extended operation as required by 10 CFR 54.21(a)(3).

Technical Information In the Application

The applicant described the Boraflex management activities aging management program (AMP) in Section B.2.2 of the LRA. The applicant stated that this AMP provides for aging management of the spent fuel rack neutron poison material. The applicant stated that these activities include the monitoring of the condition of Boraflex by routinely sampling fuel pool silica levels and periodically performing in situ measurements of boron-10 areal density. These activities are based on EPRI guidelines.

The applicant found that since this AMP is based on the use of industry guidelines and PBAPS and industry operating experience, there is reasonable assurance that the Boraflex management activities will continue to adequately manage the effects of aging of spent fuel rack Boraflex so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

Staff Evaluation

The staff's evaluation of the Boraflex management activities focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicates that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant described the program scope of the PBAPS Boraflex management activities as managing the effects of spent fuel rack Boraflex material degradation to ensure that the intended function is maintained. The applicant further stated that these activities are based on EPRI guidelines and include routine monitoring and trending of silica in the spent fuel pool and periodically performing in situ measurement of boron-10 areal density. The staff found the scope of the program to be acceptable because the applicant adequately addressed the components whose aging effects could be managed by the application of the Boraflex management activities.

Preventive or Mitigative Actions: The Boraflex management activities AMP monitors the condition of Boraflex to ensure that its degradation is detected before a loss of intended function. No preventive or mitigative attributes are associated with these activities. The staff found this program attribute acceptable because the staff considers monitoring activities a means of detecting, not preventing, aging and, therefore, agrees that there are no preventive actions associated with this AMP.

Parameters Monitored or Inspected: The silica in fuel pool water is monitored for indication of loss of boron from the matrix and degradation of the matrix itself. Measurement of the boron-10 areal density of in-service spent fuel storage rack panels is used to monitor neutron attenuation capability. The staff found the monitoring of the parameters following EPRI guidelines to be adequate to mitigate aging degradation for the spent fuel rack neutron poison material.

Detection of Aging Effects: The applicant stated that Boraflex degradation from change in material properties will result in release of silica boron carbide from Boraflex and result in increased levels of silica in fuel pool water and loss of boron-10 areal density. The applicant further stated that these parameters are monitored in accordance with EPRI guidelines at a frequency that assures identification of unacceptable aging effects before loss of intended function. The staff indicated that the amount of boron carbide released from the Boraflex panel is determined through direct measurement of boron areal density and the levels of silica determined by the use of a predictive code such as RACKLIFE or other similar codes. Therefore, the staff requested additional information on the applicant's use of the data on silica levels and the loss of boron area density.

The applicant responded, in a letter to the NRC dated May 14, 2002, that the data on silica levels are monitored for the prediction of loss of boron carbide and would signal potential degradation of Boraflex. The applicant further stated that silica is also used as an input to the EPRI RACKLIFE computer code. The staff found this program attribute acceptable because the applicant follows EPRI guidelines which have long-been, accepted for industry use. The staff also found that the program activities may be relied upon to provide reasonable assurance that aging effects will be detected before there is loss of intended function.

Monitoring and Trending: The applicant stated that monitoring of change in material properties is accomplished through the periodic measurements of boron-10 areal density of in-service spent fuel storage rack panels and sampling of silica levels in fuel pool water. This data is used to trend and predict performance of Boraflex. The staff found the applicant's approach to monitoring and trending activities to be acceptable because it is based on methods that are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible.

Acceptance Criteria: The applicant stated that analysis has shown that Boraflex will perform its intended function if degradation is maintained at less than a 10% uniform loss and at less than 10-cm randomly distributed gaps. The applicant described these parameter limits as ensuring that CLB fuel pool reactivity limits (keff > 0.95 or 5% margin) are not exceeded. The applicant further stated that spent fuel pool silica data are trended and compared to an industry-wide EPRI database. A sustained increasing trend in spent fuel pool silica concentration, inconsistent with previous seasonal/refueling changes, requires an engineering evaluation to determine the need for corrective action.

The staff requested additional information on the trending and comparison to an industry-wide database. The applicant responded, in a letter to the NRC dated May 14, 2002, that silica data is transmitted to EPRI periodically for analysis and trending and that the results are compared with data from other licensees who participate in the collaborative Boraflex research agreement with EPRI. The staff found the acceptance criteria specified by the applicant and the participation in an industry-wide data comparison agreement to be adequate to ensure the intended functions of the systems, structures, and components that may be served by the Boraflex management activities.

Operating Experience: The applicant stated that NRC Information Notices IN 87-43, IN 93-70, and IN 95-38 address several cases of significant degradation of Boraflex in spent fuel pools. In response to these findings, NRC issued Generic Letter 96- 04. The applicant further stated that the industry formed a Boraflex Working Group with EPRI and developed a strategy for tracking Boraflex performance in spent fuel racks, detecting the onset of material degradation, and mitigating its effects. The applicant described the Peach Bottom spent fuel racks and Boraflex as having been in service since 1986, and that in situ testing of representative Boraflex panels was conducted in 1996 for Unit 2 and 2001 for Unit 3. Test results identified Boraflex degradation; however, the degradation is less severe than experienced in the industry. The applicant indicated that continued testing would identify unacceptable degradation prior to loss of intended function. The staff found that the aging management activities described above are based on plant and industry experience and EPRI/industry working group participation. Therefore, the staff agreed that these activities are effective at maintaining the intended function of the systems, structures, and components that may be served by the Boraflex management activities, and can reasonably be expected to do so for the period of extended operation.

UFSAR Supplement

The staff reviewed Section A.2.2 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff has reviewed the information provided in Section B.2.2 of the LRA and the summary description of the Boraflex management activities in Section A.2.2 of the UFSAR Supplement

(Appendix A of the LRA). In addition, the staff considered the applicant's response to the staff's RAIs provided in a letter to the NRC dated May 14, 2002. On the basis of this review and the above evaluation, the staff found that there is reasonable assurance that the applicant has demonstrated that the effect of aging within the scope of this evaluation will be adequately managed with the Boraflex management activities so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

Fuel Pool Chemistry Program

The staff review of the fuel pool chemistry activities is in Section 3.0.3.22 of this SER.

3.5.2.3 Conclusions

The staff has reviewed the information in Section 3.5.2 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in the reactor building structure will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.5.3 Other Structures

3.5.3.1 Technical Information in the Application

The aging management review results for structures outside containment are presented in Tables 3.5-3 through 3.5-12 of the LRA. Each of these aging management review tables lists the (1) component groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) aging management activities. The structural components listed in Tables 3.5-3 through 3.5-12 of the LRA are in the following structures:

- radwaste building and reactor auxiliary bay
- turbine building and main control room complex
- emergency cooling tower and reservoir
- station blackout structure and foundation
- yard structures
- stack
- nitrogen storage building
- diesel generator building
- circulating water pump structure
- recombiner building

A brief description of each of the above structures is provided in Section 2.4 of the LRA. In response to RAI 2.5-1, the applicant, by letter dated May 22, 2002, supplemented its LRA to include additional station-blackout-related SSCs that should be included within the scope of license renewal and subject to an AMR. The materials of construction are concrete, masonry block, steel, carbon and galvanized carbon, cast iron, aluminum, and gravel and sand.

The components of the structures outside containment are exposed to sheltered, outdoor, raw water, and buried environments.

3.5.3.1.1 Aging Effects

Tables 3.5-3 through 3.5-12 of the LRA and Table 2 of the response to RAI 2.5-1 identify the following applicable aging effects for components in structures outside the reactor building and containment:

- loss of material of carbon steel components in an outdoor environment
- change in material properties for reinforced concrete walls in a raw water outdoor environment
- cracking, loss of material, and change in material properties for concrete foundation, walls, slabs, and precast panels of station blackout structures in outdoor and sheltered environments
- cracking, loss of material, and change in material properties for masonry block walls in station blackout structures
- loss of material for galvanized carbon steel in station blackout structures in an outdoor environment

3.5.3.1.2 Aging Management Programs

Tables 3.5-3 through 3.5-12 of the LRA credit only the Maintenance Rule Structural Monitoring Program with managing the aging effects for the components in structures outside the reactor building and containment. Table 2 of the response to RAI 2.5-1 credits the Maintenance Rule Structural Monitoring Program with managing the aging effects for components in station blackout structures. A description of the Maintenance Rule Structural Monitoring Program is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the components in structures outside containment will be adequately managed by this AMP such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.3.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports," and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the components in structures outside the reactor building and containment have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for the aging effects and the applicant's programs credited for the aging management of the components in structures outside the reactor building and containment at each Peach Bottom unit. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for components in structures outside the reactor building and containment.

3.5.3.2.1 Aging Effects

Concrete and Masonry Block walls: Tables 3.5-3 through 3.5-12 of the LRA identify change in material properties as an applicable aging effect for the reinforced concrete walls of the emergency cooling tower and reservoir. For other concrete components in outdoor, sheltered, or buried environments, Table 3.5-3 through 3.5-12 do not identify any applicable aging effects. Table 2 of the response to RAI 2.5-1 identifies cracking, loss of material, and change in material properties as aging effects for concrete foundations, walls, slabs, and precast panels of station blackout structures in outdoor and sheltered environments.

As noted above in Section 3.5.1.2.1 of this SER, the staff considers loss of material, cracking, and change in material properties to be both plausible and applicable aging effects for all concrete components, including masonry block walls, in all of the environments listed by the applicant. The NRC staff position regarding the aging management of in-scope concrete structures and components (SCs) is that they need to be periodically inspected in order to adequately monitor their performance or condition in a manner that allows for the timely identification and correction of degraded conditions. In RAI 3.5-1, the staff requested further information regarding the applicant's determination that management of concrete aging is not required. In response to RAI 3.5-1, the applicant stated that it disagrees with the staff's position regarding the aging management of concrete structures; however, the applicant has decided that it will manage concrete and masonry block wall aging during the period of extended operation. The applicant specifically stated that it will monitor concrete and masonry block wall structures for loss of material, cracking, and change in material properties through the Maintenance Rule Structural Monitoring Program. Since this commitment from the applicant covers the outdoor and sheltered concrete components in structures outside the reactor building, this response is considered to be acceptable to the staff. RAI 3.5-1 is considered closed with respect to the concrete components in structures outside the reactor building.

For the buried concrete components in structures outside the reactor building, the staff has determined that aging management is unnecessary if applicants are able to show that the soil/groundwater environment is nonaggressive. In response to RAI 3.5-1, the applicant provided water chemistry results that show that the Peach Bottom soil/groundwater environment is nonaggressive (pH = 7.2, sulfates = 38 ppm, and chlorides = 24 ppm). Consequently, the applicant concluded that the aging management of concrete in inaccessible areas is not required. Since the groundwater chemistry at the Peach Bottom site is well above the limit for pH (5.5) and below the limits for sulfates (1500 ppm) and chlorides (500 ppm), the staff concurs with the applicant's conclusion that the groundwater is nonaggressive with respect to concrete. Therefore, concrete in inaccessible areas does not need to be managed by the applicant.

Steel: The applicant identified loss of material of carbon steel components in an outdoor environment as an applicable aging effect for steel components in structures outside the reactor building.

The staff concurs with the aging effects identified above by the applicant for carbon steel exposed to an outdoor environment. However, the staff noted in Part 2 of RAI 3.5-2, that no aging effects are identified in Tables 3.5-3 through 3.5-12 for the carbon steel components in sheltered environments. In response to Part 2 of RAI 3.5-2, the applicant stated that it disagrees with the staff's position that carbon steel components in a sheltered environment require aging management. However, in response to RAI 3.5-2, the applicant committed to monitor carbon steel components in a sheltered environment for loss of material. This commitment includes all of the carbon steel components in structures outside the reactor building exposed to a sheltered environment for which the applicant did not originally identify any aging effects. Accordingly, the staff considers the applicant's response to RAI 3.5-2 with respect to carbon steel components in sheltered environments to be adequate.

For carbon steel in a buried environment, the applicant stated in its response to RAI 3.5-2 that:

> The only carbon steel structural components in a buried environment, which are within the scope of license renewal, are foundation piles for the diesel generator building (Table 3.5-10). As discussed in the PBAPS Updated Final Safety Report (UFSAR) Section 12.2.5, the building is founded on steel H piles and concrete shear walls, which are supported on rock. Selection of steel piles is based on the results of foundation studies considering field explorations and laboratory tests. The piles are driven to refusal and designed for a maximum load of 60 tons per pile. They support only gravity loads while the shear walls support lateral loads.
>
> The piles were driven into the reclaimed area of Conowingo Pond or in the backfilled areas where the rock was excavated during plant construction. According to EPRI TR-103842, "Class I Structures License Renewal Industry Report: Revision 1," and NUREG 1557, "Summary of Technical Information and Agreements form Nuclear Management and Resources Council Industry Reports Addressing License Renewal," steel piles driven in undisturbed soils have been unaffected by corrosion and those driven in disturbed soil experience minor to moderate corrosion to a small area of the metal. Thus, the loss of material aging effect, due to corrosion, is non-significant and will not impact the intended function of piles.

The applicant's response is consistent with the staff position stated in NUREG-1557 regarding steel piles and is based on industry operating experience. As such, the staff considers the applicant's response to be acceptable.

Galvanized carbon steel: the applicant listed that galvanized carbon steel used in sheltered and outdoor environments in Table 2 of its response to RAI 2.5-1 for structures and support components related to station blackout. The applicant identified loss of material as an aging effect for galvanized carbon steel in the outdoor environment and credited the Maintenance Rule Structural Monitoring Program with managing the aging effect. The applicant identified no aging effect for galvanized carbon steel in the sheltered environment. The staff considers the applicant's response to be acceptable.

Cast Iron: Table 3.5-11 of the LRA does not identify any aging effects for the cast iron/carbon steel sluice gates of the circulating water pump structure, which are exposed to a raw water and sheltered environment. In RAI 3.5-3, the staff requested further information concerning the applicant's AMR for the cast iron/carbon steel sluice gates of the circulating water pump structure. In response, the applicant committed to monitor loss of material of the sluice gates using the Outdoor, Buried, and Submerged Component Inspection Activities. The applicant's response to RAI 3.5-3 is acceptable to the staff.

Aluminum: Table 2 of the applicant's response to RAI 2.5-1 for structures and support components related to station blackout structures lists aluminum used for supporting members, sidings, electrical and instrumentation enclosures, and raceways. The applicant states that there are no aging effects for aluminum and therefore no aging management activities are required for aluminum materials. This is consistent with industry experience and the staff accepts the applicant's assessment.

3.5.3.2.2 Aging Management Programs

Tables 3.5-3 through 3.5-12 of the LRA credit only the Maintenance Rule Structural Monitoring Program with managing the aging effects for the components in structures outside the reactor building and containment. However, in response to RAI 3.5-3, the applicant committed to monitor loss of material of the cast iron/carbon steel sluice gates using the Outdoor, Buried, and Submerged Component Inspection Activities. Both the Maintenance Rule Structural Monitoring Program and the Outdoor, Buried, and Submerged Component Inspection Activities are credited with managing the aging of several components in several different structures and systems and are, therefore, considered common aging management programs. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.3.3 Conclusions

The staff has reviewed the information in Sections 3.5.3 through 3.5.12 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the components in structures outside the reactor building and containment will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.4 Component Supports

3.5.4.1 Technical Information in the Application

The aging management review results for component supports are presented in Table 3.5-13 of the LRA. Table 3.5-13 of the LRA identifies the component support groups, intended functions, environments, materials of construction, aging effects, and aging management activities.

The component groups for the component supports, as listed in Table 3.5-13 of the LRA, are support members, anchors, and grout.

Section 2.4.13 of the LRA states that the support member component group includes supports for piping and components, HVAC ducts, conduits, cable trays, instrumentation tubing trays, electrical junction and terminal boxes, electrical and I&C devices, instrument tubing, and supports for major equipment, including pumps, transformers, and HVAC fans and filters.

The anchor component group is the part of the component support assembly used to attach electrical panels, cabinets, racks, switchgears, enclosures for electrical and instrumentation equipment, pipe hangers, pumps, transformers, and HVAC fans and filters to other components or structures. Welds are used for steel attachments, and undercut anchors, expansion anchors, cast-in-place anchors, and grouted-in anchors are used for concrete attachments.

The grout component group includes grouted support pads and grouted base plates. Grout is used for constructing equipment pads and for filing and leveling equipment bases them to their respective foundations.

The materials of construction for the component supports which are subject to aging management review are carbon steel, stainless steel, alloy steel, galvanized steel, aluminum, bronze, graphite, and grout.

The component supports are exposed to internal (sheltered), outdoor, raw water, and torus water environments.

3.5.4.1.1 Aging Effects

Table 3.5-13 of the LRA identifies the following applicable aging effects for the component supports:

- loss of material for the emergency cooling water carbon steel anchors and support members exposed to an outdoor environment
- loss of material for carbon, alloy, and stainless steel support members exposed to a raw or torus water environment
- cracking of stainless steel support members exposed to torus water

3.5.4.1.2 Aging Management Programs

Table 3.5-13 of the LRA credits the following aging management programs with managing the aging effects for the component supports:

- ISI Program
- Torus Water Chemistry
- Maintenance Rule Structural Monitoring Program

A description of these aging management programs is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the component supports will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.4.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports" and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the component supports have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's programs credited for the aging management of the component supports at Peach Bottom. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the component supports.

3.5.4.2.1 Aging Effects

Steel: The applicant identified loss of material for carbon steel component supports exposed to outdoor, raw water, and torus water environments. The applicant also identified loss of material for alloy and stainless steel components exposed to raw water and torus water environments. In addition, the applicant identified cracking as an aging effect for stainless steel support members exposed to torus water.

The staff concurs with each of the above aging effects that were identified for steel component supports. However, the staff also considers loss of material to be an applicable aging effect for carbon steel component supports in sheltered environments. As such, in RAI 3.5-2, the staff requested that the applicant justify its AMR results, which did not identify any aging effects, for carbon steel components in sheltered environments. In response to RAI 3.5-2, the applicant stated that disagreed with the staff position, but it will use the Maintenance Rule Structural Monitoring Program or the ISI program to manage loss of material for carbon steel component supports in sheltered environments. These additional components, whose aging effects will now be managed during the period of extended operation, are carbon steel anchors and support members. Since the applicant committed to manage loss of material for carbon steel component supports in sheltered environments, the staff considers RAI 3.5-2 closed.

Grout: Grout is used in the construction of equipment pads, and for filling and leveling equipment bases and setting them to their respective foundations. The applicant did not identify any applicable aging effects for grout and as a result, the staff requested in RAI 3.5-3 further information regarding this determination. In response, the applicant stated:

> As in concrete components, PBAPS AMRs did not identify any aging effects for grout that will result in loss of intended function. As a result, we concluded that an aging management activity is not required. However, considering the staff's position on concrete, we will monitor accessible grout for cracking using the PBAPS Maintenance Rule Structural Monitoring Program.

The applicant's commitment to monitor grout for cracking is acceptable to the staff. Thus, RAI 3.5-3, with respect to grout, is considered closed.

Bronze/Graphite: Table 3.5-13 of the LRA does not identify any aging effects for the bronze/graphite Lubrite plates used as component supports. In Part 1 of RAI 3.5-3, the staff requested further information regarding the applicant's AMR for Lubrite plates. In response, the applicant stated:

> Lubrite is the trade name for a low-friction lubricant material used in applications where relative motion (sliding) is desired. At PBAPS, Lubrite plates are incorporated in the design of limited component supports to reduce or release horizontal loads due to temperature transients and SRV discharges.
>
> PBAPS AMRs determined that there are no known aging effects for the Lubrite material that would lead to a loss of intended function. As explained by previous applicants and concurred by the staff, Lubrite resists deformation, has a low coefficient of friction, resists softening at elevated temperatures, absorbs grit and abrasive particles, is not susceptible to corrosion, withstands high intensities of radiation, and will not score or mar. In addition, lubrite products are solid, permanent, completely self-lubricating, and require no maintenance as documented in NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4." A search of PBAPS and industry operating experience found no reported instances of lubrite plate degradation or failure to perform their intended function. On this basis, Exelon maintains that lubrite plates require no aging management.

The staff concurs with the applicant's response to RAI 3.5-3 with respect to the need for managing the aging of lubrite plates. The applicant's AMR of lubrite material is consistent with industry experience. The staff considers Part 1 of RAI 3.5-3 to be closed.

Aluminum: Aluminum is used for some of the support members. The applicant does not identify any aging effects for aluminum because the aluminum support members are located in a sheltered environment. Thus no AMR is required for aluminum. The staff concurs with this finding.

3.5.4.2.2 Aging Management Programs

Table 3.5-13 of the LRA credits the following aging management programs with managing the identified aging effects for component supports:

- Maintenance Rule Structural Monitoring Program
- ISI Program
- Torus Water Chemistry

Each of the above aging management programs are credited with managing the aging of several components in various different structures and systems. These programs are, therefore, considered common aging management programs. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.4.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the component supports will be adequately managed so that there is reasonable assurance that these supports will perform their intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.5 Hazard Barriers and Elastomers

3.5.5.1 Technical Information in the Application

The aging management review results for the hazard barriers and elastomers are presented in Table 3.5-14 of the LRA. Table 3.5-14 of the LRA identifies the components in the hazard barrier and elastomer component group as well as the component (1) functions, (2) materials, (3) environments, (4) aging effects, and (5) aging management programs.

The materials of construction of the hazard barriers and elastomers are

- carbon steel
- silicone
- rubber
- neoprene
- boot fabric (BISCO)
- fire stop putty
- grout cement
- alumina silica
- resin
- adhesive
- subliming compound
- cementitious fireproofing
- polysulfide sealant

The hazard barriers and elastomers listed in Table 3.5-14 of the LRA are exposed to sheltered and outdoor environments.

3.5.5.1.1 Aging Effects

Table 3.5-14 of the LRA identifies the following applicable aging effects for the hazard barriers and elastomers:

- cracking
- delamination and separation
- change in material properties
- loss of material
- loss of sealing

3.5.5.1.2 Aging Management Programs

Table 3.5-14 of the LRA credits the following aging management programs with managing the aging effects for the hazard barriers and elastomers:

- Door Inspection Activities
- Fire Protection Activities
- Maintenance Rule Structural Monitoring Program

- Primary Containment ISI Program

A description of these aging management programs and activities is provided in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the hazard barriers and elastomers will be adequately managed by these aging management programs such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.5.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports" and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the hazard barriers and elastomers have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's programs credited for the aging management of the hazard barriers and elastomers at Peach Bottom. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management programs that are credited for managing the identified aging effects for the hazard barriers and elastomers.

3.5.5.2.1 Aging Effects

Elastomers: The applicant identified cracking, change in material properties, separation and delamination, and loss of sealing as applicable aging effects for the elastomers listed in Table 3.5-14 of the LRA. However, for the neoprene reactor building blowout panel seals and the silicone reactor building metal siding gap seals, the applicant did not identify any applicable aging effects. Therefore, in RAI 3.5-3, the staff requested that the applicant justify its AMR results for these two components. Regarding the neoprene reactor building blowout panel seals, the applicant stated:

> PBAPS AMRs determined that the neoprene seals are susceptible to change in material properties and cracking, due to thermal exposure and ionizing radiation, only if the operating temperature exceeds 160° F or the radiation exceeds 10^6 rads. The seals for the reactor building blowout panels are located in an environment where the temperature does not exceed 112° F and the maximum total integrated gamma dose is less than 3.5×10^5 rads for 60 years. On this basis, the AMRs concluded that change in material properties and cracking aging effects are not applicable to the reactor building blowout panel seals.

Regarding the silicone reactor building metal siding gap seals, the applicant stated:

> The silicone seal specified for the reactor building metal siding is either Dow Corning product No. 732 or 790. According to the Dow Corning materials group, the products are capable of sustaining long-term temperatures greater than 158°

F. The lowest threshold radiation dose for silicone is 10^6 rads. The silicone seals for the reactor building metal siding are located in an environment where the temperature does not exceed 112° F and the maximum total integrated gamma dose is less than 3.5×10^{15} rads for 60 years. On this basis, PBAPS AMRs concluded that change in material properties and cracking aging effects are not applicable to the reactor building metal siding silicone seals.

Since the temperature and radiation limits for the neoprene blowout panel seals and the silicone metal siding gap seals are well above the actual values for the reactor building, the staff concurs with the applicant's determination that there are no applicable aging effects for these two components. The staff finds that the applicant has properly identified the applicable aging effects for the elastomers.

Fire Proofing: For the fire proofing wraps, the applicant identified change in material properties and loss of material as applicable aging effects. The staff finds that the applicant has properly identified the applicable aging effects for the fire proofing wraps.

Steel: For the carbon steel hazard barrier doors, the applicant identified loss of material as an applicable aging effect for the doors that are exposed to an outdoor environment. For the carbon steel hazard barrier doors in a sheltered environment, the applicant did not identify loss of material as an applicable aging effect. In RAI 3.5-2, the staff requested that the applicant justify its determination that loss of material is not an applicable aging effect for carbon steel hazard barrier doors in a sheltered environment. In response to RAI 3.5-2, the applicant committed to monitor loss of material due to corrosion for the carbon steel hazard barrier doors in a sheltered environment. The staff finds the applicant's commitment to be acceptable.

3.5.5.2.2 Aging Management Programs

Table 3.5-14 of the LRA credits the following aging management programs with managing the identified aging effects for the hazard barriers and elastomers:

- Door Inspection Activities
- Fire Protection Activities
- Maintenance Rule Structural Monitoring Program
- Primary Containment ISI Program

Each of the above programs is credited with managing the aging of several components in various different structures and systems and are, therefore, considered common aging management programs. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.5.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the hazard barriers and elastomers will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.6 Miscellaneous Steel

3.5.6.1 Technical Information in the Application

The aging management review results for miscellaneous steel components are presented in Table 3.5-15 of the LRA. Table 3.5-15 of the LRA identifies (1) the component groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) aging management programs.

Section 2.4.15 of the LRA states that the miscellaneous steel group includes platforms, grating, stairs, ladders, steel curbs, handrails, kick plates, decking, instrument tubing trays, and manhole covers. Each of the miscellaneous steel components listed in Table 3.5-15 of the LRA is constructed of carbon steel and exposed to either a sheltered or an outdoor environment.

3.5.6.1.1 Aging Effects

Table 3.5-15 of the LRA does not identify any applicable aging effects for the miscellaneous steel components.

3.5.6.1.2 Aging Management Programs

Since there are no aging effects identified for the miscellaneous carbon steel components in Table 3.5-15 of the LRA, the applicant does not credit any aging management programs.

3.5.6.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports" and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the miscellaneous steel components have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for aging effects of the miscellaneous steel components at Peach Bottom. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects.

3.5.6.2.1 Aging Effects

For the miscellaneous steel components identified in Table 3.5-15 of the LRA, the applicant did not identify any applicable aging effects. Since the miscellaneous steel components are constructed of carbon steel and exposed to both sheltered and outdoor environments, the staff requested in RAI 3.5-2 that the applicant justify its AMR for these components. In response to RAI 3.5-2, the applicant stated that it will monitor the miscellaneous carbon steel components exposed to sheltered environments for loss of material using its Maintenance Rule Structural Monitoring Program. The following miscellaneous steel components listed in Table 3.5-15 of the LRA will now be monitored by the Maintenance Rule Structural Monitoring Program:

- platforms
- grating
- stairs
- ladders
- steel curbs
- handrails
- kick plates
- instrument tubing trays

The staff concurs with the applicant's commitment to manage the aging of the miscellaneous carbon steel components listed in Table 3.5-15 of the LRA.

For the manhole covers, which are the only carbon steel components listed in Table 3.5-15 of the LRA that are exposed to an outdoor environment, the applicant stated in response to RAI 3.5-2:

> Manhole covers are heavy-duty type gray iron castings, manufactured by NEENAH Foundry Company to ASTM A48.74, AASHTO M105-621, and Federal QQI-625c standards. The higher silicon content and the presence of graphite flakes contained in the ferrous materials for these castings provide natural corrosion resistance. The covers have been widely used by utilities and highway departments in extreme/severe outdoor environments for several decades. Experience with the covers has shown that loss of material due to corrosion is non-significant and will not impact the intended function of the covers. As a result, aging management of manhole covers is not required.

The staff concurs with the applicant's determination that the manhole covers are rugged, heavy-duty materials that have withstood severe environments with little degradation for long periods of time. Therefore, aging management of the manhole covers is unnecessary.

3.5.6.2.2 Aging Management Programs

Table 3.5-15 of the LRA does not list any aging management programs for the miscellaneous steel components; however, in response to RAI 3.5-2 the applicant has committed to using the Maintenance Rule Structural Monitoring Program to manage the aging effects for the miscellaneous steel components in sheltered environments. The Maintenance Rule Structural Monitoring Program is credited with managing the aging of several components in various different structures and systems and is, therefore, considered a common aging management program. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.6.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the miscellaneous steel components will be adequately managed so that there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.7 Electrical and Instrumentation Enclosures and Raceways

3.5.7.1 Technical Information in the Application

The aging management review results for electrical and instrumentation enclosure and raceway component group are presented in Table 3.5-16 of the LRA. Table 3.5-16 of the LRA identifies the (1) component groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) aging management programs.

Section 2.4.16 of the LRA states that the electrical and instrumentation enclosures and raceways group includes cable trays, cable tray covers, drip shields, rigid and flexible electrical conduits and fittings, wireway gutters, panels, cabinets, and boxes.

The materials of construction for the electrical and instrumentation enclosures and raceways are carbon steel, aluminum, and galvanized carbon steel.

The electrical and instrumentation enclosures and raceways are exposed to both sheltered and outdoor environments.

3.5.7.1.1 Aging Effects

Table 3.5-16 of the LRA does not identify any applicable aging effects for the electrical and instrumentation enclosures and raceways.

3.5.7.1.2 Aging Management Programs

Since no aging effects are identified in Table 3.5-16 of the LRA, no aging management programs are listed for the electrical and instrumentation enclosures and raceways.

3.5.7.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports" and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the electrical and instrumentation enclosures and raceways have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for aging effects of the electrical and instrumentation enclosures and raceways at Peach Bottom. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects.

3.5.7.2.1 Aging Effects

Steel: Table 3.5-16 of the LRA does not list any aging effects for the electrical and instrumentation enclosures and raceways. Since carbon steel is listed as one of the materials of construction for the electrical and instrumentation enclosures and raceways, the staff requested in RAI 3.5-2 further information regarding the applicant's AMR for these components.

In response the applicant stated:

> Carbon steel components in this commodity group are constructed of factory baked painted steel or galvanized castings and sheet metal. The components are located in a sheltered environment, which is nonaggressive and does not contain high moisture. In some locations, such as the main control room, and the emergency switchgear room, the environment is air conditioned and controlled. As documented in NUREG/CR-4715, "Aging Assessment of Relays and Circuit Breakers and System Interactions," the components do not have a tendency to age with time.
>
> Industry operating experience with metal housing systems, in similar environments, indicates that they have performed with failure to the present as documented in SAND93-7069, "Aging Management Guideline for Commercial Nuclear Power Plants-Motor Control Centers," and SAND93-7027, "Aging Management Guideline for Commercial Nuclear Power Plants-Electrical Switchgear." PBAPS operating experience is consistent with the industry operating experience. As a result, our position remains that loss of material, due to corrosion, will not impact the intended function of components listed in Table 3.5-16. Thus no aging management is required.

The staff concurs with the applicant's AMR for the electrical and instrumentation enclosures and raceways. Since these components are constructed of factory-baked painted steel or galvanized castings and sheet metal and in controlled environments, aging degradation of the electrical and instrumentation enclosures and raceways should be minimal. The applicant committed to monitor loss of material aging effect of galvanized carbon steel conduits in the outdoor environment using the PBAPS Fire Protection Activities (B.2.9). Therefore, the staff considers RAI 3.5-2 to be closed with respect to the electrical and instrumentation enclosures and raceways.

Aluminum: Aluminum is used for some of the electrical and instrumentation enclosures and raceways. The applicant states that there are no aging effects for aluminum and therefore no aging management activities are required for aluminum materials. This is consistent with industry experience and the staff accepts the applicant's assessment.

3.5.7.2.2 Aging Management Programs

Since no aging effects are identified in Table 3.5-16 of the LRA, no aging management programs are listed for the electrical and instrumentation enclosures and raceways.

3.5.7.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that there are no aging effects for the electrical and instrumentation enclosures and raceways.

3.5.8 Insulation

3.5.8.1 Technical Information in the Application

The aging management review results for the insulation commodity group are presented in Table 3.5-17 of the LRA. Table 3.5-17 of the LRA identifies (1) the component groups, (2) intended functions, (3) environments, (4) materials of construction, (5) aging effects, and (6) aging management programs.

Section 2.4.17 of the LRA states that the insulation commodity group includes all insulating materials within the scope of license renewal that are used in plant areas where temperature control is considered critical for system and component operation or where high room temperatures could impact environmental qualification. The plant areas that require temperature control are the interiors of drywell, the HPCI and RCIC pump rooms, and the outboard MSIV rooms. Outdoor piping and components also require heat tracing for freeze protection.

The insulation materials include stainless steel and aluminum mirror insulation and fiberglass blanket insulation with either stainless steel or aluminum jacketing. Other insulation materials are calcium silicate or fiberglass blankets covered by an aluminum jacket. Equipment insulation consists of either calcium silicate blocks or removable ceramic-fiber blankets.

Insulation at Peach Bottom is found in both sheltered and outdoor environments.

3.5.8.1.1 Aging Effects

Table 3.5-17 of the LRA identifies insulation degradation as an applicable aging effect for the aluminum insulation jacketing with stainless steel straps that is exposed to an outdoor environment.

3.5.8.1.2 Aging Management Programs

Table 3.5-17 of the LRA credits the Outdoor, Buried, and Submerged Component Inspection Activities with managing the aging effect insulation degradation. This aging management program is described in Appendix B of the LRA. The applicant concludes that the effects of aging associated with the insulation will be adequately managed by the Outdoor, Buried, and Submerged Component Inspection Activities such that there is reasonable assurance that the intended functions will be maintained consistent with the CLB during the period of extended operation.

3.5.8.2 Staff Evaluation

In addition to Section 3.5 of the LRA, the staff reviewed the pertinent information provided in Section 2.4, "Scoping and Screening Results: Structures and Component Supports," and the applicable aging management program descriptions provided in Appendix B of the LRA to determine whether the aging effects for the insulation have been properly identified and will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

This section of this SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's program credited for the aging management of the insulation at Peach Bottom. The staff's evaluation includes a review of the aging effects considered and the basis for the applicant's elimination of certain aging effects. In addition, the staff has evaluated the applicability of the aging management program that is credited for managing the identified aging effect for the insulation.

3.5.8.2.1 Aging Effects

Table 3.5-17 of the LRA identifies insulation degradation as an applicable aging effect for aluminum insulation with stainless steel strips that is exposed to an outdoor environment. For insulation in sheltered environments, the applicant did not identify any applicable aging effects.

The staff finds that the applicant's approach for evaluating the applicable aging effects for the insulation to be reasonable and acceptable. The staff concludes that the applicant has properly identified the aging effect for the insulation.

3.5.8.2.2 Aging Management Programs

Table 3.5-17 of the LRA credits the Outdoor, Buried, and Submerged Component Inspection Activities with managing insulation degradation. The Outdoor, Buried, and Submerged Component Inspection Activities are credited with managing the aging of several components in several different structures and systems and are, therefore, considered a common aging management program. The staff review of the common aging management programs is in Section 3.0 of this SER.

3.5.8.3 Conclusions

The staff has reviewed the information in Section 3.5 of the LRA as well as the applicable aging management program descriptions in Appendix B of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the insulation will be adequately managed so that there is reasonable assurance that this component will perform its intended function in accordance with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6 Aging Management of Electrical and Instrumentation and Controls

The applicant described its AMR results for the Peach Bottom electrical/I&C components requiring AMR in Section 3.6 of the LRA. The applicant stated that Tables 3.6-1, 3.6-2, and 3.6-3 provided the results of the aging management reviews for the electrical commodities and station blackout system components within the scope of license renewal and that are subject to an aging management review. Because the commodities are not associated with one particular system but could be in any in-scope system, they were evaluated using a "spaces" approach.

The spaces evaluation was based on areas where bounding service environmental parameters were identified. For example, the temperature bounding service environmental parameter is the highest average service temperature present in the defined space, taking into account the ambient temperature (and ohmic heating where applicable). This bounding value is then compared to the 60-year limiting service temperature. The 60-year limiting service temperature is the temperature at which the insulation material experiences no aging effect which would cause the insulation material to lose its intended function for the period of extended operation.

The process used to perform an aging management review of a commodity or component group for a specific environmental stressor is as follows:

- Identify the component group materials of construction.
- Identify the aging effects for the component group when exposed to the environmental stressor.
- Determine the value of the bounding service environmental parameter to which the component groups in the area to be reviewed are exposed.
- Compare the aging characteristics of the identified materials in the bounding service environmental parameter against the 60-year limiting service environmental parameter, and determine if the component groups are able to maintain their intended function during the period of extended operation.

The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effect of aging on the electrical/I&C components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.1 Cables

3.6.1.1 Technical Information in the Application

In Section 2.5.1 of the LRA, the applicant stated that there are approximately 39,000 installed cables at PBAPS. Electrical cables were treated as a commodity group during the aging management review process. This group includes all documented cables within the scope of license renewal that are used for power, control, and instrumentation applications. The intended function of electrical cables is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals. Electrical cables are located in sheltered environment. Although EQ cables are reviewed as TLLAs, all documented cables, whether EQ or Non-EQ, were assumed to be in scope and to require aging management review.

The applicant indicated that cable insulation material groups for both safety-related and non-safety-related cables were assessed on the basis of common materials and their respective material aging characteristics.

The applicant used the plant database as the primary tool to identify cable insulation groups and to screen electrical cables for the cable aging management review. The database contains a cable code. The cable code identifies a unique cable size, application (power, control, or instrumentation), and insulation. Cable insulation groups and their applications were the determining factors in performing the assessment against bounding parameters.

The electrical cable aging management review for radiation and temperature utilized a plant "spaces" approach, whereby aging effects were identified and bounding environmental parameters were used to evaluate the identified aging effects with respect to component intended function.

3.6.1.1.1 Aging Effects

The applicant states that the stressors potentially affecting loss of material properties for cables at PBAPS are moisture, temperature, and radiation.

Moisture is of concern because of a phenomenon called "water treeing." To be identified as being susceptible to aging effects caused by water treeing, a Non-EQ cable must be exposed to long-term standing water, be energized more than 25% of the time, carry medium voltage (4kV-34.5kV for PBAPS), and be constructed of insulation material containing a void or impurity (inclusion, flaw).

The industry and manufacturers recognized this issue in the late 70s. Improved formulations (more resistant to water treeing) have been available and used since 1980. PBAPS recognized this issue and initiated a cable replacement program in 1995 to replace "suspected" cables that met the water treeing criteria described above. No cable failures have occurred at PBAPS since the cable replacement program was initiated. The applicant concluded that moisture is not an aging effect requiring management at PBAPS.

The remaining stressors affecting loss of material properties of cable insulation at PBAPS are temperature and radiation. Applying the "spaces" approach to the identification of the temperature and radiation stressors was a primary focus for the aging management review of cables. Maintaining adequate dielectric properties of the cable insulation is essential for ensuring that the electrical cables perform their intended function.

A review of cable insulation aging effects from radiation was performed by comparing the lowest radiation cable insulation with the highest radiation area where cables that support components within the scope of license renewal may be present in the plant. The value used for the highest radiation area was obtained by multiplying the existing radiation design value by 1.5 to obtain the 60-year value and then adding the accident dose. All other cable insulation types were bounded by this analysis. No cables requiring aging management as a result of radiation effects were identified.

A review of cable insulation aging effects from temperature required a more detailed elimination process. Cable populations were grouped according to their common cable insulation material type and voltage application (power, control, or instrumentation). For each cable insulation material type, a 60-year limiting service temperature was established. This value was compared to the bounding cable service temperature to determine if it was below the 60-year limiting service temperature. Ohmic heating was considered for power cables and for control cables that are routed with power cables, where applicable to determine the bounding service temperature. A summary of each cable group review follows:

- <u>Computer Cable Groups</u>

  Computer cable groups are not in the scope of license renewal and were eliminated from the temperature review.

- Fibre Optic & Bare Ground Cable Groups

  Fibre optic cable insulation material is unaffected by thermal aging. Bare ground cables have no insulation and were determined not to be within the scope of license renewal.

- Instrumentation Cable Groups

  Instrumentation cable groups with cross-linked polyethylene (XLPE), polyethylene, cross-linked polyolefin (XLPO), hypalon, Teflon-based, and polypropylene insulation were determined to have 60-year limiting service temperature greater than the bounding ambient temperature of PBAPS. Two bounding ambient temperatures were determined: one bounding ambient temperature for containment and another bounding ambient temperature for all other plant areas.

- XLPE Power & Control Cable Groups

  XLPE insulated cable groups can operate continuously at their bounding service temperature for greater than 60-years. The 60-year limiting service temperature is greater than bounding ambient temperature and its associated ohmic heating temperature rise.

- EPR Power & Control Cable Groups

  EPR (ethylene polymer rubber) cable groups supplying loads not in the scope of license renewal were eliminated from review. The remaining EPR cable groups were determined to be routed in areas outside containment and have 60-year limiting service temperature greater than the bounding ambient temperature and its associated ohmic heating temperature rise.

- PE Power and Control Cable Groups

  The routing of PE (polyethylene) power and control cable groups was determined and local ambient temperature field measurements were conducted in bounding cases. The 60-year limiting service temperature for PE insulation groups was greater than the bounding ambient temperature and its associated ohmic heating temperature rise.

- PVC Cable Groups

  Poly-vinyl-chloride (PVC) cables groups and individual cables from the remaining PVC cable groups supplying loads not in the scope of license renewal were eliminated from review. The remaining PVC cables were reviewed to identify cables with 60-year limiting service temperatures greater than the bounding service temperature. Thirty cables relied upon for fire safe shutdown (FSSD) were determined to require aging management.

- Miscellaneous Cable Groups

  Miscellaneous cables groups not in the scope of license renewal loads were eliminated from review. Miscellaneous cable groups were also reviewed to eliminate cables with a

60-year limiting service temperature greater than the bounding ambient temperature. Individual cables within the remaining group were reviewed to identify cables within the scope of the environmental qualification aging management activity or cables supplying loads not within the scope of license renewal. None of the miscellaneous cables were identified as requiring management.

3.6.1.1.2 Aging Management Program

Table 3.6-1 of the LRA provides the aging management review results for cables. In this table, no aging management activity is identified except for PVC insulated fire safe shutdown cables. The applicant states that a cable replacement program was initiated in 1995 to replace "suspected" cables subject to the water-treeing. No cable failures have occurred at PBAPS since the cable replacement program was initiated. Therefore, moisture is not an aging effect requiring management at PBAPS. The applicant also states that the maximum operating doses of insulation material (1.5 times the existing radiation design value plus the accident dose) will not exceed the 60-year service limiting radiation dose. The maximum operating temperature of insulation material will also not exceed the maximum temperature for 60-year life. The applicant concludes that no aging management programs are required for cables due to heat or radiation.

The fire safe shutdown (FSSD) inspection activity is a new aging management program. The applicant reviewed the PVC cable groups and determined that 30 cables relied upon for fire safe shutdown require aging management. These cables have a 60-year service temperature greater than the bounding service temperature. These cables are located in the drywell and are all MSRV discharge line thermocouple wires. The inspection will manage change in material properties of the PVC insulation.

3.6.1.2 Staff Evaluation

The staff evaluated the information on aging management presented in LRA, Sections 2.5.1and 3.6 and in the applicant's response to the staff RAIs dated January 2 and April 29, 2002, and November 26, 2002. The staff evaluation was conducted to determine if there is a reasonable assurance that the applicant has demonstrated that the effects of aging will be adequately managed, consistent with its CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3). This section of this SER provides the staff's evaluation of the applicant's aging management review of aging effects and the applicant's program credited for the aging management of insulated cables at Peach Bottom. The staff's evaluation includes a review of the aging effects considered. In addition, the staff has evaluated the applicability for the aging management program that is credited for managing the identified aging effects for the insulated cables.

3.6.1.2.1 Aging Effects

A cable replacement program was initiated in 1995 to replace "suspected" cables that met the water treeing criteria. Water treeing is moisture intrusion to the cable insulation that results in a decrease in the dielectric strength of the conductor insulation, which in turn results in cable failure. The applicant concluded that moisture is not an aging affect requiring management at PBAPS. It was not clear to the staff why moisture has not been an aging effect requiring management at Peach Bottom since the cables were replaced. The staff requested that the applicant provide details about the cable replacement program and explain why moisture is not an aging effect requiring management for these new cables. In a response dated January 2, 2002, the applicant stated that water treeing affects cable insulation materials having an ethylene polymer base. Water treeing has been shown to occur predominately in cables with cross-linked polyethylene (XLPE) insulation. The cable manufacturers and the utility industry recognized the water treeing phenomenon in the 1970s and improved formulations (resistant to water treeing) of XLPE cable insulation used in underground applications since 1980.

PBAPS experienced a series of nonsafety cable failures between 1984 and 1991, when XLPE insulated 5kV and 15kV cables failed with no cause initially identified. Analyses attributed one failure, in 1991, to water treeing. Further analysis on the other cable samples was conducted, and evidence of water trees was found in six cases. The trees were found to be extensive in some cases. A cable replacement program was initiated at PBAPS in 1995 and completed in 1999 on "suspected" cables subjected to the collective conditions listed above. The replacement cable was ethylene propylene rubber (EPR) insulated cable, pink in color, which has a low level of crystallinity with a poly-vinyl-chloride (PVC) jacket, suitable for use in wet or dry location in conduit, underground duct system, or direct buried, or aerial installations. The cables are rated for a minimum of 90 °C for normal operation, 130 °C for emergency loading operation, and 250 °C for short circuit conditions. The basic construction of the cable is either single-conductor Class B stranded base copper or aluminum, with extruded semiconducting strand screen, EPR insulation, extruded semiconducting insulation screen, bare copper shielding tape, and PVC jacket. A review of the PBAPS operating history has determined that no additional cable failures, caused by the effects of water treeing, have occurred at PBAPS since the cable replacement program was completed.

The applicant also provided a summary of a paper, "An Assessment of Field Aged 15kV and 35kV Ethylene Propylene Rubber Insulation Cables," published in the 1994 T&D Conference Proceedings in support of not having an aging management program for medium-voltage cables exposed to an adverse localized environment caused by moisture-produced water trees and voltage stress. It was not clear to the staff that the information in the paper is adequate for not having an AMP for medium-voltage cables exposed to an adverse localized environment caused by moisture-produced water trees and voltage stress. The staff requested the applicant to provide an aging management program for accessible and inaccessible medium-voltage (2kV-15kV) cables (e.g., installed in conduit or direct buried) exposed to an adverse localized environmental caused by moisture-produced water trees and voltage stress. In a response dated April 29, 2002, the applicant reiterated its view and stated that PBAPS elected to replace cables suspected to be susceptible to water treeing. Since the replacement cables were suitable for use in wet environment, the applicant believes that moisture is not an aging effect requiring management at PBAPS.

The applicant also stated that a review of the manufacturer's Product Data Sheet, Section 2, Sheet 9, for Okoguard-Okoseal Type MV-90 cable. The paragraph under the heading Applications states: "Type MV cables may be installed in wet or dry environments, indoors or outdoors (exposed to sunlight), in any raceway or underground duct." The paragraph headed "Product Features" additionally states that "triple tandem extruded, all EPR system, Okoguard cables meet or exceed all recognized industry standards (UL, AEIC, NEMA/ICEA, IEEE), moisture resistant, exceptional resistance to water treeing." The above information is repeated in the manufacturer's specification, and provides a warrantee for cable failure due to defects in material or workmanship for 40 years.

The applicant believed that choosing cable capable of being installed in a wet location removes the potential for water treeing to occur. In addition, the applicant stated that a review of the PBAPS operating history has discovered no additional cable failures caused by the effects of water treeing have occurred at PBAPS since the cable replacement program was completed.

The staff acknowledges that the EPR-insulated replacement cable is more resistant to water-treeing. However, the staff still does not accept the applicant's positions that moisture is not an aging effect requiring aging management for these cables. The staff believes that the discussion and conclusion of the paper, "Assessment of Field Aged 15kV and 35kV Ethylene Propylene Rubber Insulated Cables," do not support the applicant's position that moisture is not an aging effect requiring management at PBAPS. For example, the paper concludes that aging of the EPR-insulated cables can be characterized by an increase in moisture content, growth of water trees, drop in insulation elongation, increase in dissipation factor, and decrease in AC and impulse voltage breakdown strength. Further, the data for water trees, elongation, dissipation factor, and AC and impulse strength indicate that EPR insulated cable deterioration appears to result from moisture permeating the insulation of the cable. Therefore, the applicant has not provided a sufficient technical justification for not requiring an aging management program for inaccessible medium-voltage cables and has not proposed to prevent such cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit and draining water, as needed. This was part of Open Item 3.6.1.2.1-1. The additional part of this open item is discussed in Section 3.6.3.2.1 of this SER.

In response to the Open Item 3.6.1.2.1-1, the applicant, in a letter dated November 26, 2002, committed to an AMP to manage the aging of inaccessible medium-voltage cables not subject to 10 CFR 50.49 environmental qualification requirement.

The staff evaluated the proposed aging management activity for inaccessible medium-voltage cables not subject to 10 CFR 50.49 EQ requirements. The evaluation of the applicant's proposed AMP focused on program elements rather than the details of specific plant procedures. To determine whether the applicant's aging management programs are adequate to manage the effect of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following seven elements: (1) scope of program, (2) preventive actions, (3) parameter monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (7) operating experience. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of the staff's safety evaluation report.

Scope of Program: This activity applies to inaccessible (e.g., in conduit, duct bank, or direct buried) medium-voltage cables within the scope of license renewal (including 34.5 kV SBO alternate AC source) that are exposed to significant moisture simultaneously with significant voltage. Significant moisture is defined as periodic exposure to moisture that lasts more than a few days (e.g., cable in standing water). Periodic exposure to moisture that lasts less than a few days (i.e., normal rain and drain) not significant. Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time. The moisture and voltage exposures described as significant in these definitions, which are based on operating experience and engineering judgement, are not significant for medium-voltage cables that are designed for these conditions (e.g., continuous wetting and continuous energization is not significant for submarine cables). The staff found the scope of program acceptable because it includes inaccessible medium-voltage cables within the scope of license renewal that are exposed to significant moisture with significant voltage.

Preventive Action: This activity detects loss of conductor insulation material properties prior to loss of intended function for inaccessible medium-voltage cables, not subject to 10 CFR 50.49 environment qualification requirements. There are no preventive or mitigate attributes associated with this activity. The staff finds it acceptable because the applicant will test the inaccessible medium-voltage cables that are exposed to significant voltage and standing water and no preventive actions are necessary.

Parameter Monitored/Inspected: A representative sample of in-scope, medium-voltage cables exposed to significant moisture simultaneously with significant voltage are tested to provide an indication of the condition of the conductor insulation. The specific kind of test performed will be determined prior to the initial test and is to be a proven test for detecting deterioration of the insulation. Each test performed for a cable may be a different type of test. The staff requested the applicant to provide the basis of a sample selection of in-scope, medium-voltage cables to represent all inaccessible medium-voltage cable groups. In response to the staff's request, in a letter dated November 26, 2002, the applicant states that all cables within the scope of this program will be categorized into groups based on such factors as environment, type of routing (direct buried or buried ductbank), kV rating (4kV to 34.5 kV), and type of conductor insulation (e.g., EPR or XLPE). Of the cables in each of these cable groups, a representative sample of approximately 25% will be tested so that all cable groups are sampled. The staff found the applicant's response acceptable because the applicant provided a basis for sample selection that will represent all inaccessible medium-voltage cable groups

Detection of Aging Effects: In-scope, medium-voltage cables exposed to significant moisture simultaneously with significant voltage are tested at least one every 10 years. This is an adequate period to preclude failure of the conductor insulation since experience has shown that aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate. The first tests for license renewal are to be completed prior to the period of extended operation. The staff believes, based on current knowledge, that aging degradation of this cabling would be due to slow acting mechanisms. Therefore, the applicant's proposed test schedule is acceptable.

Monitoring and Trending: Trending actions are not required as part of this activity which is consistent with the GALL report. The applicant stated that the results not meeting acceptance criteria are entered into the corrective action program.

Acceptance Criteria: The acceptance criteria for each test are defined by the specific type of test performed and the specific cable tested. The staff finds such acceptance criteria acceptable as they will be based on current industry standards, which, when implemented, will ensure that the license renewal intended functions of the cables will be maintained consistent with the CLB.

Operating Experience: PBAPS has experienced several failure of XLPE cables due to water-treeing. A replacement program was initiated in 1995 to replace suspected cables with EPR cable, which is highly resistant to treeing. The replacement program was completed in 1999. No age related failures of the replaced cables have occurred. PBAPS and industry experiences support both the need for the program and the attributes of the applicant's program. Thus, the staff finds that operating experience is adequately incorporated into the development of this new program.

This program is similar to the GALL program, XI.E3. The staff found the applicant's response acceptable because the inaccessible medium-voltage cables exposed to significant moisture simultaneously with significant voltage are tested to provide an indication of the condition of the conductor insulation. The Open Item 3.6.1.2.1-1 is, therefore, closed.

FSAR Supplement:

In its November 26, 2002, response to Open Item 3.6.1.2.1-1, the applicant also included the summary description of the AMP that is to be added to the UFSAR as follows:

A.3.5 INACCESSIBLE MEDIUM-VOLTAGE CABLES NOT SUBJECT TO 10 CFR 50.49 ENVIRONMENTAL QUALIFICATION REQUIREMENTS

In this aging management activity, in-scope, medium-voltage cables exposed to significant moisture simultaneously with significant voltage are tested to provide an indication of the condition of the conductor insulation. The specific test of test performed will be determined prior to the initial test. Each test performed for a cable may be a different type of test. This activity will provide reasonable assurance that aging effects on the conductor insulation are detected and addressed such that the intended function of these cable will be maintained for the period of extended operation. This activity will be implemented prior to the end of the initial operating license term for PBAPS.

The staff reviewed proposed Section B.3.5 of the UFSAR Supplement (Appendix B of the LRA) and verified that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with inaccessible medium-voltage cables not subject to 10 CFR 50.49 environmental qualification requirements will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.2(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

For accessible Non-EQ cables installed in adverse localized environments due to heat or radiation, in Section 2.5.1 of the LRA, the applicant states that the maximum operating doses of insulation material (1.5 times the existing radiation design value plus the accident dose) will not exceed the 60 year-service limiting radiation dose. The applicant also states that the maximum operating temperature of insulation material will not exceed the maximum temperature for 60-year life. Therefore, it concludes that no aging management is required for aging effects due heat or radiation. Additionally, on January 2, 2002, the applicant stated that a plant walk down was conducted outside containment (i.e., excluding the drywell and steam tunnel) to identify any adverse localized equipment environments. It was concluded that only the drywell PVC cables credited for fire safe shutdown required an aging management activity. The staff finds that this conclusion is not consistent with the aging management program and activities for electrical cables and connections exposed to adverse localized environments caused by heat or radiation, because conductor insulation material used in cables may degrade more rapidly than expected.

The radiation levels most equipment experience during normal service have little degrading effect on most materials. However, some localized areas may experience higher-than-expected radiation conditions. Areas prone to elevated radiation levels include areas near primary reactor coolant system piping or the reactor-pressure-vessel; areas near waste processing systems and equipment (e.g., gaseous waste system, reactor purification system, reactor water cleanup system, and spent fuel pool cooling and cleanup system); and areas subject to radiation streaming. The most common adverse localized equipment are those created by elevated temperature. Elevated temperature can cause equipment environments to age prematurely, particularly equipment containing organic materials and lubricants. The effect of elevated temperature can be quite dramatic. Areas that are prone to high temperature include areas with high temperature process fluid piping and vessels, areas with equipment that operate at high-temperature, and areas with limited ventilation. Industry operating experience indicates that aging of cables requires aging management. In a letter to the applicant dated January 23, 2002 (RAI Number 3.6-1), the staff requested the applicant to provide (1) an aging management program for accessible and inaccessible electrical cable and connections exposed to an adverse localized environment caused by heat and radiation and (2) an aging management program for accessible and inaccessible electrical cables used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance and exposed to an adverse localized environment caused by heat or radiation.

In response to the staff's request, in a letter dated April 29, 2002, the applicant states that with regard to an aging management program for accessible and inaccessible electrical cables and connections exposed to an adverse localized environment caused by heat or radiation, it understands that the staff, in the RAI, is requesting a program similar to GALL Report Program X1.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." Based on the guidance in EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments," it has been found that plant operating experience (i.e., a study of plant problem reports) and visual inspection are two methods of identifying adverse localized equipment environments (or hot spots). As discussed in its letter dated January 2, 2002, a plant walkdown was performed outside containment (i.e., not in the drywell or steam tunnel). The purpose of the walkdown was to take the local temperature data and look for adverse localized equipment environments. A digital thermometer and an infrared camera were used. No adverse localized equipment (e.g., cables within 3 feet of hot process piping) were identified during the plant walkdown. Additionally, review of PBAPS plant operating experience did not identify any Non-EQ cable and connector failures due to adverse localized equipment environments.

The applicant further states that as discussed in LRA Section 2.5.1 and Exhibit 2.5-1, Non-EQ cables in the steam tunnel were reviewed to identify if they supported any in-scope license renewal loads. None were identified. Non-EQ cables in the drywell were reviewed to identify if they support any in-scope license renewal loads. An adverse localized equipment environment was identified in the drywell for certain PVC cables. Through cable aging management review, the drywell was found to be the only adverse localized equipment environment at PBAPS for in-scope, Non-EQ cables. These cables in the drywell are PVC-insulated cables, and are used to provide safety relief valve discharge temperatures to control room temperature recorders in support of FSSD. The FSSD cables have their own aging management program, as described in LRA Section B.3.2.

Although the applicant believes a thorough review of cable insulation types was performed against the PBAPS design parameters for temperature and radiation in the presence of oxygen, and a plant walkdown did not identify any adverse localized equipment environments outside the drywell or steam tunnel, the applicant agrees to implement a Non-EQ accessible cable inspection program consistent with GALL Program XI.E1.

Table 3.6-1 of the LRA has been revised (as indicated below) to reflect this new activity. Since all accessible cables installed in an adverse environment, including power, control, and instrumentation cables will be inspected, Table 3.6-1will not differentiate between insulation types as is shown in the original application.

Table 3.6-1 Aging Management Review Results for Cable

Component Group	Component Intended Function	Environment	Material of Construction	Aging Effect	Aging Management Activity
Electrical Cables	Electrical Continuity	Sheltered	Metallic conductor with various types of organic insulation (XLPE, EPR, EP, SR, etc.)	Loss of material properties	Non-EQ Accessible Cable Aging Management Activity (B.3.3)
Electrical Cables	Electrical Continuity	Sheltered	Metallic conductor with polyvinyl chloride (PVC) insulation	Loss of material properties	FSSD Cable Inspection Activity (B.3.2)

The staff finds the applicant's response acceptable because it will implement an aging management program for Non-EQ accessible cable to manage aging effects for cables in adverse localized environment caused by heat or radiation that has been reviewed by the NRC staff in GALL and found to be acceptable.

3.6.1.2.2 Aging Management Program

FSSD Cable Inspection Activities

The staff evaluated the information on aging effects caused by significant moisture and significant voltage, heat, and radiation, as presented in Section 2.5.1 of the LRA, to determine if there is a reasonable assurance that the applicant has demonstrated that the aging effects for accessible and inaccessible Non-EQ cables will be adequately managed, consistent with the applicant's CLB for the period of extended operation.

The staff asked the applicant (NRC question 22 of September 24-25, 2001 meeting) if the FSSD cable inspection activities are for instrumentation circuits. In response the applicant stated in a letter dated January 2, 2002, that the cable inspection activity for the FSSD cables do not apply to instrumentation circuits. The FSSD cables are connected to thermocouples on the discharge of the steam relief valves (SRVs) in the drywell, and provide temperature information to a recorder in the control room. The recorder provides both annunciation and input to the plant computer when an input signal is outside a preset allowable range. Although this arrangement may be considered a type of instrument circuit, it is not "loop checked" like a true instrument circuit, but provides direct readings to the recorder. The primary concern is with the PVC insulation surrounding the thermocouple metallic conductors, not with the metallic conductors themselves. With that in mind, it was considered that the most adequate inspection activity would be a visual inspection of PVC insulation consistent with GALL Report Program XI.E1, "Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." Program XI.E2, "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Requirements Used in Instrument Circuits," uses a combination of routine calibration and surveillance tests to identify the potential existence of aging degradation. This was considered to be an inadequate activity to identify the potential aging degradation of the PVC insulation of FSSD cables. The staff agrees with the applicant because FSSD cables are not for instrumentation circuits and visual inspection program is adequate for FSSD cable.

Staff Evaluation

The staff reviewed the FSSD cable inspection activity to determine whether it will ensure that all FSSD cables will continue to perform their intended function consistent with the CLB for the period of extended operation. The staff's evaluation of the FSSD cable inspection activity focused on how the program manages the aging effect through effective incorporation of the following 10 elements: program scope, preventive action, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The application indicated that the corrective action elements, which includes the confirmation process to assure that the cause of the condition is determined and corrective action taken to preclude repetition, was credited for license renewal. Exelon procedure AD-AA-101, "Processing of Procedures and T&RMs" governs creation and revision of site procedures and was the basis for the administrative control element in all PBAPS LRA Appendix B programs. The corrective action program and procedure AD-AA-101 are in accordance with the PBAPS Quality Assurance Program, which complies with 10 CFR Part 50, Appendix B. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of safety evaluation report. The remaining seven elements are discussed below.

Program Scope: The scope of the activity includes evaluation of PVC-insulated fire safe shutdown cables in the drywell that are within the scope of license renewal. The staff found the scope of the program acceptable because the program includes all insulated fire safe shutdown cables that are subject to potentially adverse localized environments.

Preventive Actions: FSSD cable inspection activities will be conducted for condition monitoring purposes. No preventive or mitigating attributes will be associated with FSSD cable inspection activities and the staff did not identify the need for such actions.

Parameter Monitored/Inspected: The PVC insulation will be visually inspected for surface anomalies such as embrittlement, discoloration, or cracking. The staff found this approach to be acceptable because it provides means for monitoring the applicable aging effects of FSSD cables.

Detection of Aging Effects: FSSD cable inspection activities will identify anomalies in the PVC insulation surface that are precursor indications of a loss of material properties for PVC-insulated cables. The staff found this activity to be acceptable on the basis that cable inspection activity is focused on detecting change in material properties of the conductor insulation, which is the applicable aging effect when cables are exposed to higher temperature.

Monitoring and Trending: Sample size of the inspection will be identified in the inspection activity. The PVC-insulated FSSD cables will be inspected once every 10 years. The applicant clarified that the first inspection will be performed before the end of the initial 40-year license term. Trending actions are not included as part of this program because the ability to trend inspection results is limited. The staff found that the 10-year inspection frequency will adequately preclude failures of the conductor insulation since aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate. The visual technique is acceptable because it provides indication that can be visually monitored to preclude aging effects of FSSD cables. The staff also found that the absence of a trending acceptable.

Acceptance Criteria: Acceptance will require that no unacceptable visual indications of insulation surface anomalies exist that would suggest that the insulation has degraded, as determined by engineering evaluation. An unacceptable indication will be defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The staff found this acceptance criterion to be acceptable because it should ensure that the intended function of the cables is maintained under all CLB design conditions during the period of extended operation.

Operating Experience: No age-related PVC-insulated FSSD cable failures have occurred at PBAPS. The staff found that the proposed inspection program will detect the adverse localized environment of FSSD cables.

UFSAR Supplement

The staff reviewed Section A.3.2 of the UFSAR Supplement (Appendix B of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with FSSD Cable Inspection activities will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.2(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

Non-EQ Accessible Cable Aging Management Activity

Staff Evaluation

The staff evaluated the proposed Non-EQ Accessible Cable Aging Management Program. The evaluation of the applicant's proposed AMP focused on program elements rather than the details of specific plant procedures. To determine whether the applicant aging management programs are adequate to manage the effect of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following seven elements: (1) scope of program, (2) preventive actions, (3) parameter monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (7) operating experience. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of the staff's safety evaluation report.

Scope of Program: This inspection program applies to accessible electrical cables and connections (power, control, or instrumentation) within the scope of license renewal that are installed in adverse localized environments caused by heat or radiation in the presence of oxygen. Except for the low-level-signal instrumentation circuits discussed below (which are included in GALL program XI.E2), the staff concludes the scope of the program is acceptable because it includes all accessible Non-EQ cables and connections that are subject to potentially adverse localized environments of heat or radiation that could cause applicable aging effects in these cables and connections.

Preventive Action: This is an inspection program and no actions are taken as part of this program to prevent or mitigate degradation. This is acceptable because the staff did not identify the need for such actions.

Parameters Monitored or Inspected: A representative sample of accessible electrical cables and connections installed in adverse localized environments is visually inspected for cable and connection jacket surface anomalies, such as embrittlement, discoloration, cracking, or surface contamination. The staff found the inspection approach acceptable because it provides means for monitoring the applicable aging affects for accessible in-scope Non-EQ insulated cables and connections.

Detection of Aging Effects: Conductor insulation aging degradation from heat, radiation, or moisture in the presence of oxygen causes cable and connection jacket surface anomalies. Accessible electrical cables and connections installed in adverse localized environments are visually inspected at least once every 10 years. This is an adequate frequency to preclude failures of the conductor insulation since experience has shown that aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate. The first inspection for license renewal is to be completed before the period of extended operation. The staff found that a 10-year inspection frequency is an adequate period to preclude failures of the conductor insulation since aging degradation is a slow process. The visual technique is acceptable because it provides indication that can be visually monitored to preclude aging effects of accessible cables and connections.

Monitoring and Trending: Trending actions are not included as part of this program because the ability to trend inspection results is limited. The staff found the absence of trending acceptable because this inspection program is a new program.

Acceptance Criteria: The accessible cables and connections are to be free from unacceptable, visual indication of surface anomalies which suggest that conductor insulation or connection degradation exists. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the intended function. The staff found the acceptance criterion acceptable because it should ensure that the intended functions of the cables and connections are maintained under all CLB design conditions during the period of extended operation.

Operating Experience: Industry operating experience has shown that adverse localized environments caused by heat or radiation may exist for electrical cables and connections next to or above (within 3 feet of) steam generators, pressurizers, or hot process pipes such as feedwater lines. These adverse localized environments have been found to cause visually observable degradation (e.g. color changes or surface cracking) of the insulating materials on electrical cables and connections. These visual indications can be used as indicators of degradation. No age-related insulated Non-EQ cable failures due to adverse localized equipment environments have occurred at PBAPS. The staff found that the proposed inspection program will detect the adverse localized environments caused by heat or radiation of electrical cables and connections.

UFSAR Supplement

The staff reviewed the proposed Section A.3.3 of the UFSAR Supplement (Appendix B of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d). However, to be consistent with the commitment made in response to RAI 3.6-1, the applicant needs to provide a summary of description of the B.3.3, "Non-EQ accessible cable aging management activity" in the UFSAR Supplement. This was Confirmatory Item 3.6.1.2.2-1.

In response to the Confirmatory Item 3.6.1.2.2-1, in a letter dated November 26, 2002, the applicant included the following summary description of the AMP in the UFSAR Supplement:

A.3.3 Non-EQ Accessible Cable Aging Management Activity

The Non-EQ accessible cable aging management activity will visually inspect all cables and connections in accessible areas (easily approached and viewed) in the potential adverse localized environment. The Non-EQ accessible cable aging management activity will be performed once every ten years, beginning prior to the period of extended operation. This inspection activity will provide reasonable assurance that the intended function of electrical cables and connections that are not subject to environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by heat or radiation will be maintained consistent with the current licensing basis through the period of extended operation.

The staff found the response acceptable because it contains an adequate summary description of the program activities for managing the effects of the aging for the system and components as required by 10 CFR 54.21(d) and closed Confirmatory Item 3.6.1.2.2-1.

Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with Non-EQ accessible cable aging management activity will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that, the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

In response to the staff's request for an aging management program (RAI 3.6-1) for accessible and inaccessible electrical cables used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance and exposed to an adverse localized environment caused by heat or radiation, the applicant states that it understands that the staff is requesting a program similar to GALL Report Program X1.E2, "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits," which uses routine calibration tests performed as part of the plant surveillance test program to identify the potential existence of aging degradation of cables and connections used in low-level-signal instrumentation that are sensitive to reduction in insulation resistance (IR) such as radiation monitoring and nuclear instrumentation.

The applicant stated that visual inspection can detect degradation early in the aging process whereas embrittlement and cracking must occur before significant electrical property changes, such as reduced resistance, would be detected through circuit calibration. Section 5.2.2, "Measurement of Component or Circuit Properties," of SAND96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations," dated September 1996, states,

> Significant changes in mechanical and physical properties (such as elongation-at-break and density) occur as a result of thermal-and radiation-induced aging. For low-voltage cables, these changes precede changes to the electrical performance of the dielectric. Essentially, the mechanical properties must change to the point of embrittlement and cracking before significant electrical

changes are observed.

The industry understands that these two GALL programs (XI.E1 and XI.E2) manage the same aging effects for the same cables in different ways. This is seen as providing an applicant with the ability to pick the program that best fits the needs identified at the plant. Both programs are not required to adequately manage aging of plant cables. Calvet Cliffs committed to the calibration program (XI.E2) but not to the inspection program, and Oconee committed to the inspection program (XI.E1) but not the calibration program. The industry saw this as a precedent and understood as being included in the GALL Report: the two programs cover the same cables using different methods to manage aging, and the applicant can choose a program that best fits the plant aging management requirements.

The staff notes that purpose of GALL Program XI.E1 is to provide reasonable assurance that the intended function of Non-EQ electrical cables and connections that are exposed to adverse localized environments caused by heat or radiation will be maintained consistent with the CLB through the period of extended operation. The cables included in this program do not include sensitive, low-signal-level instrumentation circuits or medium-voltage power cables. In Program XI.E1 a representative sample of accessible electrical cable and connection in adverse localized environments is visually inspected for cable and connection jacket surface anomalies. If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, a determination is made as to whether the same condition is applicable to other accessible or inaccessible cables or connections. The purpose of GALL Program XI.E2 is to provide reasonable assurance that the intended functions of Non-EQ electrical cables that are used in sensitive low-level-signal circuits exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the CLB through the period of extended operation. In this program routine calibration tests performed as part of the plant surveillance test program are used to identify the potential existence of aging degradation. When an instrumentation loop is found to be out of calibration during routine surveillance testing, trouble shooting is performed on the loop, including the instrumentation cable. Thus, the two program cover different cables using different methods.

The aging management activity submitted by the applicant does not utilize the calibration approach for Non-EQ electrical cables used in circuits with low-level signals. Instead, these cables are simply combined with other Non-EQ cables under the visual inspection activity. The staff believes, however, that visual inspection alone may not necessarily detect reduced insulation resistance (IR) levels in cable insulation before the intended function is lost. Exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced IR. A reduction in IR will cause an increase in leakage current between conductors and from individual conductors to ground, and is a concern for circuits with sensitive low-level signals such as in radiation and nuclear instrumentation since reduced IR may contribute to inaccuracies in instrument loop. Because low-level-signal instrumentation circuits may operate with signals that are normally in the picoamp range or less, they can be affected by extremely low levels of leakage current. Routine calibration tests performed as part of the plant surveillance test program can be used to identify the potential existence of this aging degradation.

The staff was not convinced that aging of these cables will initially occur on the outer casing, resulting in sufficient damage that visual inspection will be effective in detecting the degradation before IR losses lead to a loss in intended function, particularly if the cables are also exposed to moisture. The staff undertook its own review of several aging management references. Page 3-52 of the SAND96-0344 report referenced by the applicant identifies polyethylene-insulated instrumentation cables located in close proximity to fluorescent lighting that had developed spontaneous circumferential cracks in exposed portions of the insulation. For some of the affected cables, the cracking was severe enough to expose the underlying conductor; however, no operational failures were documented as a result of this degradation.

Section 5.2.2 of SAND 96-0344 only assumes dry conditions where cable cracking occurs. "Aging and Life Extension of Major Light Water Reactor Components" edited by V.N Shaw and P.E. MacDonald on page 855 state that breaks in insulation systems that are dry and clean are normally not detectable with insulation resistance tests for 1000V or less. On the same page they also state that insulation resistance tests can detect some types of gross insulation damage, cracking of insulation, and the breach of connector seals, provided there is enough humidity or moisture to make the exposed leakage surfaces conductive.

Electric Power Research Institute (EPRI) report TR-103834-P1-2, "Effects of Moisture on the Life of Power Plant Cables" also supports the above view. It states on page 1.4-8 that normal or high insulation resistance may not indicate damaged insulation in that a throughwall cut or gouge filled with dry air may not significantly affect the insulation resistance. The SAND96-0344 report, on page 3-51, states that instances of low-voltage cable and wire shorting to ground induced by moisture may, in fact, be due to moisture intrusion through pre-existing cracking, an effect of thermal and/or radiation exposure.

The staff concludes from this literature that visual inspection of low-voltage, low-signal-level instrumentation circuits can be an effective means to detect age-related degradation due to adverse localized environments. The staff notes that the above finding on low-voltage instrumentation circuits is not necessarily true for neutron monitoring system cables. The SAND96-0344 report referenced by the applicant states on page 3.36 that neutron monitoring systems (including source, intermediate, and power range monitors) were evaluated as a separate category based on (1) their substantial difference from typical low- and medium-voltage power, control, and instrumentation circuits, and (2) the relatively large number of report related to these devices and identified in the database. The report states that neutron detectors are frequently energized at what is commonly referred to as "high" voltage, usually 1kV and 5kV. This is not high voltage compared to power transmission voltage, but rather elevated with respect to other portions of the detecting circuit. The report included the lower voltage non-detector portion of typical neutron monitoring equipment in the low-voltage equipment category, but put the 1kV to 5kV neutron detectors into a separate category that included neutron monitor cables and connectors.

The high-voltage portion of the neutron monitoring system would be a worst-case subset of the low-signal-level instrumentation circuit category. These circuits operate with low-level logarithmic signals so they are sensitive to relatively small changes in signal strength, and they operate at a high voltage, which could create larger leakage currents if that voltage is impressed across associated cables and connectors. Radiation monitoring cables have also been found to be particularly sensitive to thermal effects. NRC Information Notice 97-45, supplement 1, describes this phenomenon. The neutron monitoring and radiation monitors, therefore, might be candidates for the calibration approach but not necessarily the visual inspection approach.

The applicant should provide a technical justification for high range radiation monitor and neutron monitoring instrumentation cables to demonstrate that visual inspection will be effective in detecting damage before current leakage can affect instrument loop accuracy. This was identified as Open Item 3.6.1.2.2-1.

In response to the staff Open Item, in a letter dated November 26, 2002, the applicant stated that at PBAPS, the drywell high range radiation monitoring system has General Atomic radiation monitors that are EQ and identified as subject to a TLAA in PBAPS LRA Section 4.4.1. The average power range monitor (APRM), local power range monitor (LPRM), and the wide range neutron monitor (WRMN) instrumentation circuits are the non-EQ portions of the neutron monitoring system within the scope of 10 CFR 54.4. The cables for the LPRMs were replaced in the late 1990s. WRNMs were installed in the late 1990s to replace the source range monitors and intermediate range monitors. The cables for these instrumentation circuits are routed in either flex or rigid conduit. There are no cables within the APRM instrument circuits that are in an adverse localized environment caused by heat or radiation. The APRM receives the neutron monitoring data from the LPRM detectors and cables. The applicant also states that it will commit to an aging management activity for the LPRM and the WRMN instrumentation cables not subject to 10 CFR 50.49 EQ requirements. The staff found the applicant's response acceptable because the applicant proposed an AMP in which a review of calibration results of surveillance activities are used to identify the potential existence of cable aging degradation. The Open Item 3.6.1.2.2-1 was therefore closed.

The staff evaluated the proposed aging management activity for electrical cables not subject to 10 CFR 50.49 EQ requirements used in instrumentation circuits as described above. The evaluation of the applicant's proposed AMP focused on program elements rather than the details of specific plant procedures. To determine whether the applicant aging management programs are adequate to manage the effect of aging so that the intended function will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following seven elements: (1) scope of program, (2) preventive actions, (3) parameter monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, and (7) operating experience. The staff's evaluation of the applicant's corrective action, confirmation process, and administrative controls is provided separately in Section 3.0.4 of the staff's safety evaluation report.

Scope of Activity: This program applies to electrical cables used in the LPRM and the WRMN instrumentation circuits. The staff found the scope of the program did not include the electrical cables used in high range radiator monitoring system and APRM instrumentation circuits. In the conference call dated November 7, 2002, the staff requested that the applicant explain why these cables were not included in the AMP. The applicant responded, in a letter dated November 26, 2002, that at PBAPS, the drywell high range radiator monitoring system has General Atomic radiator monitors and cables that are EQ and identified as subject to a TLLA in PBAPS LRA Section 4.4.1. There are no cables within the APRM instrument circuits that are in an adverse localized environment caused by heat or radiation. The APRM receives the neutron monitoring data from the LPRM detectors and cables. The staff found the applicant's response acceptable because it explains why high range radiator monitoring and APRM cables are not in scope of the AMP. The staff also found the scope of the program acceptable because it includes all electrical cables used in nuclear instrumentation that are sensitive low-level signal that are subject to potentially adverse localized environment.

Preventive Actions: This is a surveillance activity. No actions are taken as part of this activity to prevent or mitigate aging degradation and the staff did not identify the need for such actions.

Parameters Monitor/Inspected: The parameters monitored are determined from the PBAPS technical specifications and are specific to the instrumentation circuit being calibrated, as documented in the surveillance activity. The staff found this approach to be acceptable because it provides means for monitoring the aging effects of the non-EQ electrical cables used in instrumentation circuits.

Detection of Aging Effect: Review of calibration results of surveillance activities can provide indication of the need for corrective actions by monitoring key parameters and providing data based on acceptance criteria related to instrumentation circuit performance. The normal calibration frequency specified in the PBAPS technical specifications provide reasonable assurance that severe aging degradation will be detected prior to the loss of the cable intended function. The staff found this acceptable on the basis that the calibration program identifies the need for corrective actions by monitoring key parameters and providing trending data based on acceptance criteria. The staff also found that the normal calibration frequency specified in the plant technical specifications provide reasonable assurance that aging degradation will be detected prior to loss of cable intended function.

Monitoring and Trending: Trending actions are not required as part of this activity which is consistent with the GALL report. The applicant stated that the results not meeting acceptance criteria are entered into the corrective action program.

Acceptance Criteria: The specific type of surveillance activity being performed and the specific instrumentation circuit being reviewed as set out in the PBAPS technical specifications defines the acceptance criterion for each review. The staff found the acceptance criteria acceptable because surveillance activity as set out in the plant technical specifications should ensure that cable intended functions used in instrumentation circuits are maintained under all CLB design condition during the period of extended operation.

Operating Experience: PBAPS has experienced degradation of cables in neutron monitoring systems. The cables for the LPRMs were replaced in the late 1990s. MRNMs were installed in the late 1990s to replace source range monitors and intermediate range monitors. The cables for these instrumentation circuits are run in either flex or rigid conduit. No age related failure resulting in loss of function for these cables has occurred since the cables were replaced. The staff found the proposed calibration program will detect the adverse localized environment of electrical cables used in instrumentation circuits.

UFSAR Supplement:

In response to the staff's open item, the applicant committed to include the following summary description in the UFSAR Supplement:

A.1.17 Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirement Used in Instrumentation Circuits

This aging management activity applies to electrical cables used in the Local Power Range Monitor and Wide Range Neutron Monitor Instrumentation circuits. The periodic review of calibration test results is used to identify the potential existence of aging degradation. When an instrument circuit is found to be significantly out of calibration, additional evaluation is performed on the circuit, including the cable, as required. This activity will provide reasonable assurance that the intended functions of electrical cables that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are used in instrumentation circuits with sensitive, low-level signals exposed to adverse localized environments caused by heat, radiation, or moisture will be maintained consistent with the current licensing basis through the period of extended operation

The staff reviewed the proposed Section A.1.17 of the UFSAR Supplement (Appendix B of the LRA) and verified that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with Non-EQ electrical cables used in instrumentation circuits will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.2(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.6.1.3 Conclusions

The staff has reviewed the cable aging effects presented in Sections 2.5.1 and 3.6 of the LRA and the AMPs presented in Section B.3.2 and B.3.3 of Appendix B of the LRA as well as additional information from the applicant. On the basis of the review, the staff concludes that the applicant has demonstrated that these AMPs adequately manage the effects of aging associated with the cables that are within the scope of license renewal so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.6.2 Connectors, Splices, and Terminal Blocks

3.6.2.1 Technical Information in the Application

In Section 2.5.2 of the LRA, the applicant stated that the commodity group terminations includes electrical connectors, splices, and terminal blocks used for power, control, and instrumentation applications. PBAPS connectors, splices and terminal blocks that are part of the environmental qualification program were reviewed as time-limited aging analyses and the results are provided in Section 4.4.

The intended function of electrical connectors, splices, and terminal blocks is to provide electrical connections to specified sections of an electrical circuit to deliver voltage, current, or signals. The electrical connectors, splices, and terminal blocks are located in a sheltered environment.

The electrical connector materials subject to aging are metal and insulation. The metals used for electrical connectors are copper, tinned copper, and aluminum. The connector insulation materials used are various elastomers and thermoplastics.

The splice materials subject to aging is insulation. The insulation material used are various elastomers.

The electrical terminal block materials subject to aging are metal and insulation. The metals used for terminal blocks are copper, tinned copper, brass, bronze, and aluminum. The insulation materials used are phenolic compounds and nylon.

3.6.2.1.1 Aging Effects

The applicant does not identify any aging effects associated with connectors, splices, and terminal blocks, as indicated in Table 3.6-2 of the LRA.

3.6.2.1.2 Aging Management Program

The applicant provided the aging management review results for connectors, splices, and terminal blocks in Table 3.6-2 of the LRA. In this table, no aging management activity is required for the connectors, splices, and terminal blocks.

3.6.2.2 Staff Evaluation

The staff has evaluated the information on aging management presented in the Peach Bottom LRA, Sections 2.5.2 and 3.6, and the applicant's response to the staff RAIs, dated January 2, April 29, and November 26, 2002. The staff evaluation was conducted to determine if there is a reasonable assurance that the applicant has demonstrated that the effects of aging will be adequately managed, consistent with its CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3). This section of the SER provides the staff's evaluation of the applicant's aging management review for aging effects and the applicant's aging management program credited for the aging management of connectors, splices, and terminal blocks at Peach Bottom. The staff's evaluation includes a review of the aging effects considered. In addition, the staff has evaluated the applicability of the aging management program that is credited for managing the identified aging effects for the connectors, splices, and terminal blocks.

3.6.2.2.1 Aging Effects

The staff noted that low-voltage instrumentation circuits that are sensitive to small variations in impedance were determined to be potentially affected by oxidation of connectors and terminations that are used to terminate impedance-sensitive circuits (e.g., coaxial and triaxial connectors and terminations). Loss of materials caused by oxidation and corrosion of connector pins are aging concerns. The staff requested that the applicant provide an aging management program to manage these aging effects or provide technical justification for excluding it. In a response dated January 2, 2002, the applicant states that the connector materials subject to aging are metal and insulation. The metals used for low-voltage electrical connectors are copper, tinned copper, and aluminum. The connector insulation materials used are various elastomers and thermoplastics. Properly fitted and tight connections on uninsulated connectors protect the metallic contact surface area connection from environmental aging effects. Low-voltage (impedance-sensitive) instrumentation electrical connectors may experience failure when exposure to a wet environment induces corrosion or tarnishing of the metallic surface contact. The absence of a wet environment, with a properly fitted connection, preclude failure of an impedance-sensitive instrumentation connection through corrosion or tarnishing. Failures of electrical connectors that are not designed for wet environments are not age-related failures. Electrical connector failures resulting from water unexpectedly introduced into a normally dry area of the plant are event-driven or due to human error and are not age-related. This is confirmed in the NRC letter from Grimes to Walters, dated June 5, 1998, "License Renewal Issue No. 98-0013, 'Degradation Induced Human Activities'" which states that "the staff concludes that the issue of degradation induced by human activities need not be considered as a separate aging effect and should be excluded from aging management review." The applicant further stated in its response that a review of PBAPS operational history concluded that no age-related degradation due to oxidation of connectors has occurred at PBAPS . Therefore, the applicant concluded that no aging management activity is required. The staff finds the applicant's response acceptable because failures of electrical connectors resulting from connectors that are not designed for wet environments installed in a wet environment, are not age-related failures. Electrical connector failures, resulting from water unexpectedly introduced into a normally dry area of the plant are event-driven or due to human error and are not age-related.

Peach Bottom LRA Section B.1.13, "Standby Liquid Control System Surveillance Activities," covers standby liquid control system (SBLC) components, including the solution tank, piping and valves on the suction side of the SBLC pump. The staff requested the applicant to explain why the electrical cables, connectors, and terminations were not included in this program in order to manage the aging effects of electrical components located in boric acid environments. In response to the staff's request, the applicant states that as a boiling water reactor (BWR), PBAPS has an SBLC system like that described in Section VII.E2 of NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." The GALL report describes the components of the SBLC system in contact with a sodium pentaborate solution. The sodium pentaborate solution provides a relatively mild environment with a slightly basic pH. Peach Bottom does not have a borated water environment; therefore, GALL Report Program XI.M10, "Boric Acid Corrosion," does not apply to PBAPS. There is no boric acid corrosion of any external surfaces, including the surfaces of cables, connections, and terminations. Additionally, the connectors and cables in the SBLC system are within protected enclosures so that sodium pentaborate leakage cannot degrade conductivity. The staff find the applicant's response acceptable because boric acid corrosion does not apply to PBAPS.

Section 3.6.2 of the LRA does not identify any applicable aging effects for Non-EQ connectors, splices, and terminal blocks. Industry experience indicates that change in material properties is an aging effect for connections (connectors, spices, and terminal blocks) that require aging management. In a letter dated January 23, 2002, the staff requested the applicant to provide an aging management program to manage the aging effects of accessible and inaccessible electrical connections exposed to an adverse localized environment caused by heat or radiation (RAI 3.6-1). The applicant responded with a proposed aging management activity to manage the aging effects for connections.

Table 3.6-2 of the LRA will be revised as shown below to reflect this new activity.

Table 3.6-2 Aging Management Review Results for Connectors, Splices, and Terminal Blocks

Component Group	Component Intended Function	Environment	Material of Construction	Aging Effect	Aging Management Activity
Electrical Connectors Insulation	Electrical Continuity	Sheltered	Various organic insulation types (discussed in Section 2.5.1)	Loss of Material Properties	Non-EQ Accessible Cable Aging Management Activity (B.3.3)
Electrical Connectors Metallic Connector	Electrical Continuity	Sheltered	Copper, tinned copper, and aluminum	None (2)	Not Applicable
Electric Splices Insulation	Electrical Continuity	Sheltered	Modified Polyolefin (XLPO, XLPE)	Loss of Material Properties	Non-EQ Accessible Cable Aging Management Activity (B.3.3)
Electrical Terminal Blocks Insulation	Electrical Continuity	Sheltered	Phenolic and nylon insulation	Loss of Material Properties	Non-EQ Accessible Cable Aging Management Activity (B.3.3)
Electrical Terminal Blocks Metallic	Electrical Continuity	Sheltered	Copper, tinned copper, brass, bronze & aluminum	None (2)	Not Applicable

(2) No aging effects for PBAPS

The revised Table 3.6-2 identifies loss of material properties as an aging effect of electrical connections. The staff finds the applicant's response acceptable because loss of material properties is the aging effect of electrical connections.

3.6.2.2.2 Aging Management Programs

The applicant proposed an aging management program, "Non-EQ Accessible Cable Aging Management Activity," for connectors, splices, and terminal blocks in a letter dated April 29, 2002. This program applies to electrical connectors, splices, and terminal blocks within the scope of license renewal that are installed in adverse localized environments caused by heat or radiation in the presence of oxygen. The staff found that the submitted aging management activity is essentially a visual inspection that addresses age-related degradation of connections that can result from exposure to high values of heat or radiation. The acceptability of this AMP has been evaluated in Section 3.6.1.2.2 of this SER. The staff therefore finds the aging management activity acceptable for providing reasonable assurance that the intended functions of Non-EQ connectors, splices, and terminal blocks that are exposed to adverse localized environments caused by heat or radiation will be maintained consistent with the CLB through the period of extended operation.

In a letter dated May 16, 2002, the NRC forwarded to the Nuclear Energy Institute (NEI) and Union of Concerned Scientists, a proposed interim staff guidance (ISG) for comment on screening of electrical fuse holders. The staff position indicated that fuse holders should be scoped, screened, and included in the aging management review (AMR) in the same manner as terminal blocks and other types of electrical connections that are currently being treated in the process. This position only applies to fuse holders that are not part of a larger assembly such as switchgear, power supplies, power inverters, battery chargers, circuit boards, etc. Fuse holders in these types of active components would be considered to be piece parts of the larger assembly and not subject to an AMR.

During a conference call on September 5, 2002, the applicant stated that it will include fuse holders in the scope of the proposed AMP, Non-EQ accessible Cable Aging Management Activity (B.3.3), and this AMP will manage the aging effects for fuse connectors, splices, and terminal blocks as well as fuse holders. This was Confirmatory Item 3.6.2.2.2-1.

In response to the staff confirmatory item, by letter dated November 26, 2002, the applicant stated that based on a conference call on September 5, 2002, and conference call on September 23, 2002, to clarify the basis for the Confirmatory Item, the applicant agreed with the above position that fuse holders are passive, long-lived electrical components within the scope of license renewal , and that only those fuse holders that are not part of a larger assembly are subject to an AMR. The applicant also agreed with the statement in the May 16, 2002 letter that, for the purpose of license renewal, fuse holders/blocks are classified as a specialized type of terminal block because of the similarity in design and construction.

Section 3.6.2, Table 3.6-2 of the LRA provides the aging management review results for connectors, splices, and terminal blocks based on environment and material of construction. Since fuse holders/blocks are classified as a specialized type of terminal blocks because of similarity of design and material of construction, it was the applicant's position that there are no additional aging effects requiring management.

The staff disagreed with the applicant that there are no additional aging effects requiring management. The applicant revised Table 3.6-2 in the LRA to include the fuse holders in the Non-EQ Accessible Cable AMP. However, the AMP only address the insulation part but not the metallic parts (metallic clamps) of fuse holders. The AMP for fuse holders needs to include the following aging stressors: fatigue, mechanical stress, vibration, chemical contamination and corrosion on the metallic clamps of fuse holder. In addition, visual inspection alone may not be sufficient to detect the aging effects on the metallic clamps of the fuse holders. Therefore, the staff considered the fuse holder issue unresolved. This was considered Open Item 3.6.2.2.2-1.

In response to the Open Item, in the letter from M.P. Gallagher to the NRC dated January 14, 2003, the applicant provided a fuse inspection activity to manage the aging effects of the metallic portion of fuse holders. Subsequently, in a follow up conference call with the staff on January 27, 2003, the applicant decided to modify the aging management activity associated with the fuse holders. This was confirmed in two letters from M. P. Gallagher to NRC dated January 29 and 31, 2003. Appendix B.1.18, Fuse Inspection Activity, that was included in Attachment 2 of the January 14, 2003 letter was deleted and replaced with the following as documented in the January 29, 2003 letter:

B.3.6 Fuse Holder Aging Management Activity

Activity Description:

Staff guidance on the fuse holder issue has not been finalized at this time. When the fuse holder final guidance is issued by the NRC, Exelon will generate a new aging management activity to implement the requirements of the guidance.

UFSAR Supplement Appendix A.1.18, which was included in Attachment 2 of the January 14, 2003, was also deleted and replaced with the following:

A.3.6 Fuse Holder Aging Management Activity

After issuance of the final staff guidance regarding the aging management of fuse holders, a new aging management activity will be generated to implement the requirements of the final staff guidance. This activity will be implemented prior to the end of the initial operating license term for PBAPS.

The staff found the applicant's response to Open Item 3.6.2.2.2-1 acceptable because the applicant committed to implement the final resolution of the ISG at the end of the initial license period for PBAPS; therefore Open Item 3.6.2.2.2-1 is closed.

3.6.2.3 Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with connectors, splices, and terminal blocks will be adequately managed so there is reasonable assurance that the intended function of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21 (a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.6.3 Station Blackout System

3.6.3.1 Technical Information in the Application

In Section 2.5.3 of the LRA, the applicant states that the station blackout system is comprised of the alternate AC (AAC) power source as required per NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors." The station blackout (SBO) system for PBAPS is in compliance with 10 CFR 50.63. The AAC power source consists of the following components:

- Conowingo Hydroelectric Plant (dam)
- Susquehanna substation
- wooden takeoff pole
- manholes at Conowingo and Peach Bottom
- Submarine cable (transmission line)
- station blackout substation at PBAPS

<u>Conwingo Hydroelectric Plant (Dam)</u>

The Conowingo Hydroelectric Plant (dam) is on the Susquehanna River approximately 10 miles north of the mouth of the river on the Chesapeak Bay, 5 miles south of the Pennsylvania border, and approximately 10 miles south of PBAPS. The Dam is the source of power to support the PBAPS SBO commitment. The Federal Energy Regulatory Commission (FERC) licenses the dam and associated power block. The dam is constructed primarily of concrete and steel. The associated power block consists of reinforce concrete and structural steel.

<u>Susquehanna Substation</u>

The Susquehanna substation is adjacent to and receives power from the Conowingo Hydroelectric Plant. The substation delivers 34.5kV power to PBAPS to support the SBO requirements. The substation has the standard industry power distribution design and consists of aluminum bus bars, insulators, circuit breakers, transformers, and associated foundations.

<u>Wooden Pole</u>

The takeoff tower for the transmission line from the Susquehanna substation is a wooden pole. The pole is constructed of yellow pine and chemically treated before installation. The installed pole has been analyzed to be able to withstand the severe weather conditions associated with the SBO event.

<u>Manholes</u>

Manholes exist at both the Conowingo Hydroelectric Plant and PBAPS locations to house the transition between the standard power cables from the substations at each location and the submarine cable. The manholes are constructed of reinforced concrete. AMRs of aging effects for concrete structures have concluded that no aging management activities are required, except for change in material properties due to leaching of calcium hydroxide in the emergency cooling tower and reservoir walls.

Submarine Cable (Transmission Line)

A 35kV submarine cable exits the manhole at Conowingo and runs under the bed of the Susquehanna River from just north of the dam to a manhole just south of the SBO substation. The submarine cable consists of copper phase conductors, ground conductors, EPR insulation, metallic shielding, and polyethylene (Okolene) jackets. The assembly of the submarine cable has three individually shielded and jacketed conductors cabled together with two ground conductors, and one fiber optic cable, with polypropylene fillers as necessary. A polypropylene bedding covers the entire cable and a layer of steel armor wires is applied over the bedding. Each wire is jacketed with black polyethylene. A nylon serving is then applied and an asphaltic solution is applied both under and over the armor and nylon serving.

PBAPS SBO Substation

PBAPS SBO substation consists of 34.5kV and 13.8kV metalclad outdoor walk-in switchgear, a 15/20 MVA oil-filled transformer, and associated breakers and controls. The SBO substation is designed as a stand-alone facility with control power coming from within the switchgear. The switchgear is contained within a standard prefabricated metal enclosure. The enclosure and switchgear foundation is discussed in LRA Section 2.4.6.

3.6.3.1.1 Aging Effects

Table 3.6-3, of the LRA identifies the following aging effects for the components of the wooden poles and Conowingo Hydroelectrical Plant:

- loss of material
- change in material properties

In Table 3.6-3, the applicant indicates that aging effects for concrete are evaluated in Section 3.5.6 of the LRA and that no aging effects are identified for aluminum, porcelain, and EPR insulation of the substation bus bar, substation insulators, and submarine cable, respectively.

3.6.3.1.2 Aging Management Program

Table 3.6-3 of the LRA credits the Wooden Pole Inspection and Conowingo Hydroelectric Plant Aging Management Program for managing the aging effects for the wooden pole and Conowingo Hydroelectric Plant.

3.6.3.2 Staff Evaluation

The staff evaluated the information on aging management presented in the Peach Bottom LRA Sections 2.5.3 and 3.6.3 and the applicant's January 2, April 29, May 22, June 10, July 30, and November 26, 2002, responses to the staff RAIs. The staff evaluation was conducted to determine if there is a reasonable assurance that the applicant has demonstrated that the effects of aging will be adequately managed, consistent with its CLB throughout the period of extended operation, in accordance with 10 CFR 54.21(a)(3).

3.6.3.2.1 Aging Effects

Potential aging effects for insulators are surface contamination, cracking, and loss of material due to wear. Various airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. Porcelain is essentially a hardened, opaque glass. Like any glass, if subjected to enough force it will crack or break. The most common cause for cracking or breaking of an insulator is being struck by an object (e.g., a rock or bullet). Insulators also crack when the cement that binds the parts together expands enough to crack the porcelain. This phenomenon, known as cement growth, is caused by an improper manufacturing process which makes the cement more susceptible to moisture penetration. Mechanical wear is an aging effect for strain and suspension insulators because they move. An insulator can move when the wind blows the supported transmission conductor, swinging the conductor from side to side. If frequent enough, the swinging can cause wear in the metal contact points of the insulator string and between an insulator and the supporting hardware.

The staff requested the applicant to explain why no aging effects which require aging management was identified for bus bar insulators and the submarine cable. In response to the staff's concern regarding the aging management for bus bar insulators and submarine cables used in SBO, the applicant stated that porcelain insulators on the Susquahanna Substation bus bar and the insulator on the wooden pole were assessed for aging effects due to cracking, loss of material due to wear, and surface contamination. Cracking (known as cement growth) is caused by improper manufacturing and is not an applicable aging effect. Loss of material due to mechanical wear is an aging effect due to movement. Although this mechanism is possible, experience has shown that transmission conductors do not swing for very long once the wind has subsided. Therefore, this is not an applicable "significant and observable" aging effect. Surface contamination can be a problem in areas where there are great concentrations of airborne particles, such as near facilities that discharge soot or near the sea where salt spray is prevalent. Susquehanna substation and the wooden pole are in an area where airborne particle concentrations are comparatively low. Consequently, the contamination buildup on the insulators is insignificant, and surface contamination is not applicable aging effect. Therefore, no aging management activity is required for the bus bar and wooden pole insulators.

The submarine cable is designed for the environment it operates in (raw water). There are no aging effects from temperature and radiation. The cable is operated in an energized state with a load of approximately 1kVA. The cable is tested along with the other PBAPS SBO components every 2 years to assure it can support the required SBO loads. The PBAPS components of the SBO AAC source are maintained using procedures under the PBAPS QA program. In a letter to the applicant the manufacturer (Okonite) stated that it was "not aware of any age-related failures" of Okonite's Okoguard insulated submarine cables. Therefore, no aging management activity is required.

The staff found the applicant's response to the staff's RAI acceptable. As indicated above, the submarine cable is designed for the environment in which it operates and the contamination buildup on insulators is insignificant. The staff, therefore, concludes that the insulators and cables as defined above do not require an aging management activity at PBAPS.

During the staff visit to PBAPS on September 24 and 25, 2001, the staff questioned whether certain transitional cables within the scope of the SBO alternate AC source from the Conowingo hydroelectric plant to the PBAPS were inscope and subject to an AMR. The applicant agreed to a revised SBO system description that will include these cables and their aging effects. In a letter dated January 2, 2002, the applicant responded that:

> the original boundary for the cable (transmission line) and SBO components began at the output breaker in the Susquehanna Substation and went to the PBAPS Unit 2 start up bus 00A03C. The discussion in LRA Section 2.5.3 of the SBO alternate AC source did not specifically mention the cables spliced to the submarine cable, which occurs on land in the manholes both at Conowingo and PBAPS, nor did it specifically mention the cables from the Conowingo generator output breaker to the Susquehanna substation. These cables were considered to be bounded by the results of the Aging Management Review Technical Report for electrical cables, and were not specifically included in LRA Tables 2.5-1, 3.6-1, or 3.6-3 as a separate line item. The Cable Aging Management Review Technical Report for electrical cables used the "spaces" approach for assessing electrical cables based on insulation material and environment. The environments for the cable from the wooden pole to the manhole at Conowingo is a combination of "buried," and "outside"; the environment for the cable from the manhole at PBAPS to the SBO switchgear and Unit 2 Startup Bus 00A0C3 is "buried," and the environment for the cables from the Conowingo generators to the Susquehanna substation is a combination of "outdoor" and "sheltered." These environments are as defined in the LRA, Section 3.0. Table 3.6-3 of the LRA would be modified, due to above, to include the environment "buried" for these cables.

In addition, the applicant's response also stated that moisture was not an applicable aging effect for these cables. The staff disagreed with the applicant that moisture is not considered to be an applicable stressor for buried 35 kV cables spliced to the submarine cable. Medium-voltage cables exposed to wet conditions for which they are not designed can lead to "water treeing" which results in a decrease in the dielectric strength of the conductor insulation. This can potentially lead to electrical failure. Buried high-voltage cables are more susceptible to the "water treeing" phenomena. Therefore, the applicant had not provided a sufficient technical justification for not requiring an aging management program for inaccessible 35 kV cables and had not proposed to prevent such cables from being exposed to significant moisture, such as inspecting for water collection in cable manholes and conduit and draining water, as needed. This was part of Open Item 3.6.1.2.1-1.

In response to the staff's open item, the applicant agreed to include the 35 kV buried cables associated with SBO alternate AC source in the scope of the inaccessible medium-voltage cable AMP. This resolves the staff open item.

In a May 22, 2002, response to the staff's request for additional information on the intended electrical function of the offsite power system within the scope of license renewal that provides recovery power after SBO event, the applicant states that it will include those applicable offsite power system structures and components required to support the description of recovery within the scope of license renewal and the aging management review process, as described in the NRC letter to Alan Nelson and David Lochbaum, "Staff Guidance on Scoping of Equipment Relied on To Meet the Requirement of the Station Blackout Rule (10CFR 50.63) for License Renewal (10CFR 54.4(a)(3)," dated April 1, 2002.

The offsite power system (the substation and the 13kV system) consists of three power sources and their associated structures and components and allows for power to be provided to the 4kV safeguard busses via the 13kV system. The substations have the standard industry power distribution design and consist of switchyard bus, insulators, circuit breakers, ground and disconnect switches, transformers, offsite power line poles, and associated switchgear and control buildings, foundation and supports. The offsite power system is discussed in UFSAR Section 8.1. The electrical components comprising the offsite power system were reviewed and the following passive, long-lived components were identified as subject to an AMR:

- switchyard bus
- high-voltage insulators
- insulated cables and connections (connectors, spices, terminal blocks)
- phase bus (non-segregated-phase bus)
- transmission conductors

The intended electrical function of the offsite power system within the scope of license renewal is to provide recovery after an SBO event. The AMR results for the electrical components are shown in Table 1 of the applicant's RAI response.

In Table 1 of the applicant's May 22, 2002, response to RAI 2.5-1 the applicant indicated that switchyard bus, outdoor/buried/sheltered insulated cables and connections, non-segregated phase bus, and transmission conductors have no aging effects and do not require aging management activity. In a telephone conference on June 18, 2002, the staff requested the applicant to explain why no aging effect was identified for these components. The staff also requested the applicant to identify any operating experience of the offsite power system components associated SBO. In response dated July 30, 2002, the applicant states that pure aluminum exposed to air may be susceptible to oxidation at connection points. However, no-oxide grease, a consumable which is replaced as required during routine maintenance, prohibits oxidation. Therefore, no aging effects are applicable.

A sheltered environment is defined on page 3-6 of the LRA. A sheltered environment consists of indoor ambient conditions where components are protected from outdoor moisture. No cables and connections associated with the SBO system and offsite power are in the drywell and steam tunnel. These cables experience temperatures of less than 105 °F and humidity between 10% and 90%. Radiation levels in this environment are less than 2.0E+06 inside the plant and normal background radiation levels outside the plant. No aging effects for cables and connections in this environment require management.

An outdoor environment is defined on page 3-7 of the LRA. An outdoor environment consists of air temperatures typically ranging from 0 °F to 100 °F, and an average annual precipitation of approximately 30 inches. Radiation levels are those of normal background levels. There are no aging effects for cables and connections in this environment.

A buried environment is defined on page 3-7 of the LRA. The buried environment consists of granular bedding material of sand or rock fines, backfill of dirt or rock, and filler material of gravel or crushed stone. A buried environment may include such items as ductbanks and conduits. The buried cables and connections associated with the offsite power sources, which may be susceptible to the phenomenon of water treeing, have been replaced. Direct buried cables exist in the substation. The cables are installed in a trench constructed of bar sand or stone screening both above and below the cables, with treated planking above the covered cables. As a result the cables in the trench experience normal "rain and drain" moisture and not standing water; therefore, they are not susceptible to water treeing.

With the exception of an oil fire several years ago in the substation, which was event driven, a review of PBAPS operating history indicates that PBAPS has not experienced any age-related degradation of the cables buried in the trench. The nonsegregated bus associated with the offsite power is in a sheltered environment and has no aging effects. The non-segregated bus duct that transitions from the #2SU startup and emergency auxiliary transformer to the #2 SU startup switchgear building is in an outdoor environment, discussed with structures, and is inspected by the Maintenance Rule Structural Monitoring Program. The overhead conductor is aluminum conductor steel reinforced (ACSR). Corrosion of ACSR is a very slow-acting aging effect and is even slower for rural areas such as PBAPS with generally fewer suspended particles and SO_2 concentrations in the air than urban areas. Therefore there are no applicable aging effects that require management.

The staff finds the applicant's response acceptable for switchyard bus, outdoor/sheltered insulated cables and connections, non-segregated-phase bus, and transmission conductors because it provides the rationale for why no aging effects are identified. The staff believes that water treeing can effect buried cables (other than 35kV submarine cables) associated with the offsite source and installed in ductbanks, conduits, and trenches. The staff acknowledges that the replacement cable is an improved formulation, which is more resistant to water-treeing. However, as discussed in Section 3.6.1.2.1, the staff does not accept the applicant's position that moisture is not an aging effect requiring an aging management for these cables. The staff is concerned that the applicant has not provided a sufficient technical justification for not requiring an aging management program for buried cables, not specifically designed for a wet environment. This was the other part of Open Item 3.6.1.2.1-1.

In response to this part of Open Item 3.6.1.2.1-1, the applicant agreed to include buried cables (4kV to 34.5 kV) associated with the offsite sources in the scope of the inaccessible medium-voltage cable AMP. This resolves the staff's concern.

3.6.3.2.1 Aging Management Programs

The aging management review results for the station blackout system are provided in Table 3.6-3 of the LRA. The Conowingo Hydroelectric Plant (Dam) Aging Management Program will manage reinforced concrete and steel used in the Conowingo Hydroelectric Plant, and the Susquahanna Substation Wooden Pole Inspection Activity will manage the loss of material and change in material properties of wood used in wooden pole.

<u>Conowingo Hydroelectric Plant (Dam) Aging Management Program</u>

Section B.1.15 of the LRA describes the applicant's program for managing the potential aging of structures and components associated with the Conowingo Hydroelectric Plant dam. The staff reviewed Section B.1.15 of the LRA to determine whether the applicant has demonstrated that the inspection activities will adequately manage the applicable effects of aging during the period of extended operation as required by 10 CFR 54.21(a)(3).

The Conowingo Hydroelectric Plant is the source of power to support the PBAPS station blackout system, which was installed to meet the requirements of 10 CFR 50.63. The Conowingo dam is located on the Susquehanna River approximately 10 miles north of the mouth of the river on the Chesapeake Bay and approximately 10 miles south of PBAPS. The dam is constructed primarily of concrete and steel, and is exposed to raw water and an outside environment. The Federal Energy Regulatory Commission (FERC) licenses the dam and associated power block. The applicant credits the Conowingo Hydroelectric Plant (Dam) Aging Management Program with managing the potential loss of material of the dam.

Staff Evaluation

The applicant stated that the Conowingo Hydroelectric Plant dam is subject to the FERC 5-year inspection program. This program consists of a visual inspection by a qualified independent consultant approved by FERC, and is in compliance with Title 18 of the Code of Federal Regulations (Conservation of Power and Water Resources), Part 12 (Safety of Water Power Projects and Project Works), Subpart D (Inspection by Independent Consultant).

The applicant stated that the FERC licenses the dam and associated power block. By virtue of the FERC's authority and responsibility for ensuring that its regulated projects are constructed, operated, and maintained to protect life, health, and property, the staff finds that for earthen embankments, dams, appurtenances, and related structures subject to AMR, continued compliance with FERC requirements during the license renewal period will constitute an acceptable dam aging management program for the purposes of license renewal. Therefore, the staff finds the program acceptable.

UFSAR Supplement

The staff reviewed Section A.1.15 of the UFSAR Supplement (Appendix B of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with Conowingo Hydroelectric Plant (dam) AMP will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

<u>Susquehanna Substation Wooden Pole Inspection Activity</u>

The applicant described the Susquehanna Substation Wooden Pole (SSWP) Inspection Activity AMP in Section B.2.11 of Appendix B of the LRA. The program is used to manage loss of material and change of material properties for the SSWP. The staff reviewed the applicant's description of the AMP in Section B.2.11 of Appendix B of the LRA to determine whether the applicant has demonstrated that the program will adequately manage the aging effects of the SSWP during the period of extended operation as required by 10 CFR 54.21(a)(3).

The SSWP inspection activity AMP is used to manage loss of material and change of material properties for the SSWP, a wooden pole at the Susquehanna substation. The pole provides structural support for the conductors connecting the substation to the cable that transmits the AC power to PBAPS from the Conowingo Hydroelectric Plant for coping with station blackout. The wooden pole is subjected to outdoor and buried environments.

The AMP consists of inspection on a 10-year interval by a qualified inspector. The above-ground wooden pole exposed to the outdoor environment is inspected for loss of material due to ant, insect, and moisture damage and for change in material properties due to moisture damage. The applicant concluded that the SSWP inspection activity AMP manage the aging effects of loss of material and change in material properties so that the component intended functions will be maintained consistent with the CLB during the period of extended operation.

In accordance to 10 CFR 54.21(a)(3), the staff reviewed the information included in Appendix B of the LRA regarding the applicant's SSWP inspection activity AMP. Specifically, the LRA should demonstrate that the effects of aging due to the exposure of the wooden pole to outdoor and buried conditions will be adequately managed, allowing the intended functions to be maintained consistent with the CLB for the period of extended operation.

Staff Evaluation

The staff's evaluation of the Susquehanna substation wooden pole inspection activity focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in Section 3.0.4 of this SER. The remaining seven elements are discussed below.

Program Scope: The applicant stated that the program only applies to the SSWP. The staff finds the scope of the program acceptable.

Preventive Actions: The applicant described the AMP as a condition monitoring AMP. No preventive or mitigation actions are provided. The staff considers inspection activities a means of detecting, not preventing, aging and, therefore, agrees that no preventive actions are associated with the wooden pole inspection activity and none are required.

Parameters Monitored or Inspected: The applicant stated 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. In RAI B2.11-1, the staff requested information on what parameters and material properties are monitored/inspected and how the buried part of the wooden pole is monitored/inspected. In a letter dated June 10, 2002, the applicant responded that 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. 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 poles are found to have ground line decay they are excavated and inspected 18 inches below the ground line. If internal decay is suspected, the pole is bored to allow for further analysis. The staff finds the parameters monitored or inspected acceptable because they are capable of detecting the aging effects.

Detection of Aging Effects: The applicant stated that inspection of the wooden pole every 10 years by a qualified inspector will assure that aging effects are detected prior to loss of intended function. In the RAI B2.11-2, the staff requested justification for the 10-year inspection interval of the wooden pole. In a letter dated June 10, 2002, the applicant explained that the typical life for 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 every 10 years, as required, it should last 10 to 15 years longer. Exelon experience over several decades has indicated that a 10-year inspection interval is adequate. The Susquehanna wooden pole was installed in 1994. The first inspection is scheduled for 2003. The pole will be inspected every 10 years thereafter. The staff finds the 10-year inspection interval acceptable because it is based on plant and industry experience.

Monitoring and Trending: The applicant stated that condition monitoring for loss of material and change in material properties is provided in the corporate specification for inspection of wooden poles. The wooden pole is inspected at 10-year intervals. The monitoring under this AMP involves a combination of visual, sounding, boring, and excavation activities to determine the condition of the pole. Any 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 require immediate attention in the interest of safety are recorded, and reported. Therefore, the staff finds the applicant's approach to monitoring activities to be acceptable because it is based on methods that are sufficient to predict the extent of degradation so that timely corrective or mitigative actions are possible.

Acceptance Criteria: The applicant stated that the acceptance criteria for the inspection are provided in the corporate specification for inspection of wooden poles. In RAI B.2.11-3, the staff requested a description of the acceptance criteria in terms of (1) assessing the severity of the observed degradations and (2) determining whether corrective action is necessary. In a letter dated June 10, 2002, the applicant explained that 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. If sounding indicates internal decay, or a hollow pole, boring will determine the extent of the decayed area. Pesticide treatment will occur as required. If any poles (except poles requiring replacement) found to contain ants or termites, the cavities where the ants or termites are found are flooded with an effective preservative solution. Any pole determined to have internal decay will receive fumigant treatment. Each wooden pole that is inspected receives a condition tag describes the pole condition as found by the inspector and whether the pole has received treatment. Based on the remaining shell thickness (circumference) and pole loading, poles can be tagged as requiring either reinforcement or replacement. The staff finds the acceptance criteria acceptable.

Operating Experience: The first inspection of the pole is scheduled for 2003, so there is no experience with this specific pole; however, the applicant stated that corporate experience shows that inspection of wooden poles once every 10 years is adequate to detect aging degradation prior to loss of intended function, based on corporate and industry experience. The staff finds this reasonable and acceptable.

UFSAR Supplement

The staff reviewed Section A.2.11 of the UFSAR Supplement (Appendix B of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management of systems and components discussed above is equivalent to the information in NUREG-1800 and therefore provides and adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The staff concludes that the applicant has demonstrated that the aging effects associated with Susquehanna Substation Wooden Pole Inspection Activity will be adequately managed so there is reasonable assurance that the intended functions of the systems and components will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

3.6.3.3 Conclusions

The staff has reviewed the Station Blackout system aging effects presented in Section 3.6.3 of the LRA and the AMPs presented in Sections B.1.15 and B.2.11 of Appendix B of the LRA. On the basis of the review, the staff concludes that the applicant has demonstrated that these AMPs adequately manage the effects of aging associated with Station Blackout systems components that are within the scope of license renewal so that the intended functions will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities for managing the effects of aging for the systems and components discussed above as required by 10 CFR 54.21(d).

4 TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

4.1.1 Introduction

The applicant describes its identification of time-limited aging analyses (TLAAs) in Section 4.1.1, "Identification of Time-Limited Aging Analyses," of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has identified the TLAAs as required by 10 CFR 54.21(c) and described them in its UFSAR Supplement as required by 10 CFR 54.21(d).

In Section 4.1 of the application, the applicant described the requirements for the technical information to be reported in the application regarding time-limited aging analyses (TLAAs), as stated in 10 CFR 54.21(c). These include a list of TLAAs, as defined in 10 CFR 54.3, "Definitions," and a list of plant-specific exemptions granted pursuant to 10 CFR 50.12 that are based on TLAAs. The applicant also described the criteria used to identify TLAAs at Peach Bottom, Units 2 and 3. These criteria are the same as the six criteria stated in 10 CFR 54.3 for identifying TLAAs.

The identified TLAAs were evaluated and the results are described in Sections 4.1 through 4.7 of this SER. As required by 10 CFR 54.21(c), the applicant has provided a list of TLAAs in Table 4.1-1 of the LRA. The applicant also stated that no plant-specific exemptions based on TLAAs have been granted at Peach Bottom.

4.1.2 Summary of Technical Information in the Application

The applicant evaluates calculations for Peach Bottom against the six criteria specified in 10 CFR 54.3 to identify the TLAAs. The applicant identifies the following TLAAs:

- Reactor vessel neutron embrittlement
    - 10 CFR Part 50 Appendix G reactor vessel rapid failure propagation and brittle fracture considerations: Charpy upper shelf energy (USE) reduction and RT_{NDT} increase, reflood thermal shock analysis
    - Reactor vessel thermal limit analysis: operating pressure-temperature limit (P-T limit) curves
    - Reactor vessel circumferential weld examination relief
    - Reactor vessel axial weld failure probability

- Metal fatigue
    - Reactor vessel fatigue
    - Reactor vessel internals fatigue and embrittlement
    - Reactor vessel internals fatigue analyses
    - Reactor vessel internals embrittlement analyses
    - Effect of fatigue and embrittlement on end-of-life reflood thermal shock analysis

- Piping and component fatigue and thermal cycles
- Fatigue analyses of Group I primary system piping
- Assumed thermal cycle count for allowable secondary stress range reduction in Group II and III piping and components
- Design of the RHR system for a finite number of cycles
- Effects of reactor coolant environment on fatigue life of components and piping (Generic Safety Issue 190)

- Environmental qualification of electrical equipment
- Loss of prestress in concrete containment tendons not applicable
- Containment fatigue

  - Fatigue analyses of containment boundaries: new loads analysis of torus, torus vents, and torus penetrations
  - New loads fatigue analysis of SRV discharge lines and external torus-attached piping
  - Expansion joint and bellows fatigue analyses (drywell-to-torus-vent bellows)
  - Expansion joint and bellows fatigue analyses (containment penetration bellows)

- Other plant-specific TLAAs

  - Reactor vessel corrosion allowances
  - Generic Letter 81-11 crack growth analysis to demonstrate conformance to the intent of NUREG-0619
  - Fracture mechanics of ISI-reportable indications for Group I piping: as-forged laminar tear in a Unit 3 main steam elbow

Pursuant to 10 CFR 50.21(c)(2), the applicant stated that no exemptions granted under 10 CFR 50.12 on the basis of a TLAA were identified. The applicant states that a technical alternative (as defined in 10 CFR 50.55a(a)(3)(i)) to requirements to inspect circumferential welds on the reactor pressure vessel has been approved by NRC. This TLAA is discussed in Section 4.2.3 of this SER.

In a separate licensing action, the applicant has submitted a license amendment for a power uprate to increase the maximum allowed operating power level. This power uprate is based on the increased accuracy of feedwater flow monitors. The higher power level may result in higher reactor coolant temperatures, increased reactor coolant flow, and/or increased neutron fluence. On July 23, 2002, the staff held a conference call with the applicant to ask if the the effects of the power uprate were considered during its evaluation of the TLAAs or that the analysis results are bounding for the higher power level. The applicant stated that the effects of the power uprate were considered. In response to Confirmatory Item 4.1.2-1, by letters dated November 26 and December 19, 2002, the applicant indicated that as part of the power uprate, a separate RPV fracture toughness evaluation was performed. The evaluation confirmed that the combined effects of license renewal and power uprate on fluence, adjusted reference temperature, and upper shelf energy at the end of the license renewal period are bounded by the values provided in the license renewal application Furthermore, no additional aging effects that require management are applicable due to the small increase in steam flow resulting from the power uprate. The applicant has adequately addressed the effects of the power uprate and license renewal by confirming the results of the power uprate and license extension are bounded by the results identified in the license renewal application.

4.1.3 Staff Evaluation

TLAAs are defined in 10 CFR 54.3 as analyses that meet the following six criteria:

- involve systems, structures, and components within the scope of license renewal, as delineated in 10 CFR 54.4(a)
- consider the effects of aging
- involve time-limited assumptions defined by the current operating term (for example, 40 years)
- were determined to be relevant by the applicant in making a safety determination
- involve conclusions or present the basis for conclusions related to the capability of the system, structure, or component to perform its intended functions, as delineated in 10 CFR 54.4(b)
- are contained or incorporated by reference in the CLB

In addition, to the TLAAs listed in Section 4.2 through 4.7 of the LRA, the staff identified three other potential TLAAs. The evaluation of these potential TLAAs is provided below.

<u>Flaw Growth Analyses</u>

Feedwater and Control Rod Drive Nozzles

Table 4.1-1 of the LRA identifies flaw growth analysis as a TLAA for feedwater nozzles and control rod drive return line nozzles. The table, however, does not identify the flaw growth analyses for other reactor coolant pressure boundary components as TLAAs. Flaws in Class 1 components that exceed the size of allowable flaws defined in IWB-3500 of the ASME Code need not be repaired if they are analytically evaluated to the criteria in IWB-3600 of the ASME Code. The analytic evaluation requires the applicant to project the amount of flaw growth due to fatigue or stress corrosion cracking mechanisms, or both where applicable, during a specified evaluation period. In RAI 4.1-1, the staff requested the applicant to identify all Class 1 components that have flaws exceeding the allowable flaw limits defined in IWB-3500 and that have been analytically evaluated to IWB-3600 of the ASME Code and submit the results of the analyses that indicate whether the flaws will satisfy the criteria in IWB-3600 for the period of extended operation. In response, the applicant stated that Exelon reviewed all preservice and inservice inspection summary reports as part of the effort to identify all potential TLAAs. Exelon reviewed all dispositions which might have included an IWB-3600 evaluation.

The only other flaw evaluated with time-dependent methods similar to IWB-3600 for the licensed operating period is a laminar indication in a Unit 3 main steam elbow (discussed in Section 4.7.3 of the LRA). This section describes the condition, the original fatigue calculation, and the basis for validating the calculation for the extended licensed operating period.

No other flaws evaluated with time-dependent methods similar to IWB-3600 extended to the end of the current licensed operating period. Since no other flaw evaluations met TLAA criteria, the staff find the applicant's response that such flaw evaluations were not TLAAs acceptable.

Pipe Break Locations

The applicant did not identify postulated pipe breaks locations based on the cumulative usage factor (CUF) as a TLAA for Peach Bottom. Although the applicant identified the fatigue usage factor calculation as a TLAA, the applicant did not identify the pipe break criteria as a TLAA. The usage factor calculation used to identify postulated pipe break locations meets the definition of a TLAA as specified in 10 CFR 54.3. In a teleconference on May 6, 2002, the staff requested the applicant to provide a description of the TLAA performed to address the pipe break criteria for Peach Bottom. In addition, the staff requested the applicant to identify any postulated pipe breaks locations based on CUF and describe the TLAA performed for these locations.

The applicant's June 10, 2002, response indicated that pipe breaks had been postulated at Peach Bottom locations where the CUF exceeds 0.1. The applicant also indicated that it did not expect the number of design transients assumed in these CUF calculations to be exceeded in 60 years of plant operation. Therefore, the CUF calculations which form the basis for the Peach Bottom pipe break postulations remain valid for the period of extended operation.

The Peach Bottom Unit 2 recirculation system piping was replaced in 1985-86 and the Unit 3 piping in 1988-89. The replacement was designed to ASME Section III Class 1 requirements. Peach Bottom UFSAR 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 reanalyzed in 2001 to consider extended operation and no new breaks were identified. The analysis for extended operation used a piping life of 47 years for Unit 2 and 44 years for Unit 3, not 60 years, because the original piping has been replaced. The same screening criterion, 0.1 CUF, was used in all of the analyses. In addition, as identified in 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."

The applicant indicated that it did not expect the number of design transients assumed in these CUF calculations to be exceeded during the period of extended operation. Therefore, the Peach Bottom pipe break postulations remain valid for the period of extended operation in accordance with the requirements of 10 CFR 54.21(c)(1). The staff finds that the applicant's response is acceptable because the existing calculations are bounding for the period of extended operation. The staff concludes that the applicant has adequately evaluated the TLAA related to pipe breaks as required by 10 CFR 54.21(c). In the draft safety evaluation, the staff indicated that the UFSAR update needs to include a summary of the activities for the evaluation of this TLAA. This is was identified as Confirmatory Item 4.1.3-1.

The applicant's November 26, 2202, response to the open and confirmatory items referenced the CUF criteria in UFSAR Section A.10.3.3 used for postulating pipe breaks in the recirculation piping pipe breaks. The applicant also indicated that the reactor pressure vessel recirculation inlet and outlet nozzles and the RHR tee connections to the recirculation line are included in fatigue management program discussed in Section A.4.2 of the UFSAR Supplement. The staff finds that the applicant's UFSAR update contains an appropriate summary description of the activities to evaluate TLAAs related to fatigue as required by 10 CFR 54.21(d).

Crane Load Cycle Limit

In Section 4.1 of the LRA, the applicant did not identify a crane load cycle limit as a TLAA for the cranes within the scope of license renewal. Normally, based on the design code of the crane, a load cycle limit is specified at rated capacity over the crane's projected life. Therefore, it is generally necessary to perform a TLAA relating to crane load cycles estimated to occur up to the end of the extended period of operation.

By letter dated February 6, 2002, the staff requested additional information, per RAI 3.3-3, as to why the crane load cycle limit was not included as a TLAA. The applicant responded in a letter dated May, 6, 2002, in which it stated that it will update the UFSAR Supplement to include load cycles for the reactor building overhead bridge cranes, turbine hall cranes, emergency diesel generator bridges, and circulating water pump structure gantry crane as a TLAA in Section 4.7.4 of the LRA. In the response, the applicant stated that the cranes are predominantly used to lift loads which are significantly lower than the crane's rated load capacity. For example, the reactor building cranes will undergo less than 5000 load cycles in 60 years based on the projected number of lifts during refueling outages, handling of spent fuel storage casks, and testing. The other cranes are expected to experience significantly fewer load cycles than the reactor building cranes. Thus, the number of lifts at or near their rated load is low compared to the design limit of 20,000 load cycles. The applicant stated that the load cycles for these cranes were evaluated for the period of extended operation and it was determined that the analyses associated with crane design, including the load cycle limit, remain valid for the period of extended operation and, therefore, meet the requirements of 10 CFR 54.21(c)(1)(i). The staff agrees with the applicant's conclusion that the cranes will continue to perform their intended function throughout the period of extended operation as required by 10 CFR 54.21 (c)(1) and finds the applicant's response acceptable. The UFSAR Supplement needs to include a summary description of the evaluation of this TLAA ~~is~~ as required by 10 CFR 54.21(d). This was Confirmatory Item 4.1.3-2.

On November 26, 2002, the applicant provided the UFSAR Supplement. In Section A.5.7 of the UFSAR Supplement, the applicant provided a summary description of its evaluation of this TLAA for the period of extended operation. The description contains the basis for determining that the analyses associated with crane design, including the load cycle limit, remain valid for the period of extended operation and therefore, meet the requirements of 10 CFR 54.21(c)(1)(i). On the basis of its review of the information provided in Section A.5.7 of the UFSAR Supplement, the staff concludes that the applicant has provided adequate summary description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d) and therefore, the confirmatory Item 4.1.3-2 is closed.

4.1.4 Conclusions

The staff has reviewed the information provided in Section 4.1 of the Peach Bottom LRA. The NRC staff concludes that the applicant has adequately identified the TLAAs as required by 10 CFR 54.21(c), and that no 10 CFR 50.12 exemptions have been granted on the basis of the TLAA as defined in 10 CFR 54.3. The staff also concludes that the applicant has adequately evaluated the TLAAs related to pipe breaks and the crane load cycle limit as required by 10 CFR 54.21 (c).

4.2 Reactor Vessel Neutron Embrittlement

4.2.1 10 CFR Part 50 Appendix G Reactor Vessel Rapid Failure Propagation and Brittle Fracture Considerations: Charpy Upper Shelf Energy (USE) Reduction and RT_{NDT} Increase, Reflood thermal shock analysis

4.2.1.1 Summary of Technical Information in the Application

The applicant described its evaluation of this TLAA in LRA Section 4.2, "Reactor Vessel Neutron Embrittlement."

Neutron Irradiation Embrittlement

Neutron irradiation causes a decrease in the Charpy upper shelf energy (USE) and an increase in the adjusted reference temperature (ART) of the reactor pressure vessel (RPV) beltline materials. The ART impacts the plant's pressure-temperature (P-T) limit and RPV integrity evaluations. BWRVIP-74 report contains integrity evaluations of the BWR RPV circumferentially oriented welds and the BWR RPV axially oriented welds. Therefore, in order to demonstrate that neutron embrittlement does not significantly impact BWR RPV integrity during the license renewal term, the applicant must determine the end-of-life fluence and the end-of-life RT_{NDT}, determine the validity of the reflood thermal shock analysis, and evaluate the impact of neutron irradiation on the Charpy USE reduction, P-T limits, RPV circumferential welds, and RPV axial welds.

Neutron Fluence and RT_{NDT}

The application does not contain the calculations for determining the end-of-life fluence and end-of-life RT_{NDT}. The application indicates that the applicant will initiate the calculations for end-of-life fluence using the GE fluence methodology after the NRC approves it. Then the applicant will recalculate the vessel end-of-life RT_{NDT} for a 60-year licensed operating life (54 EFPYs) according to Code Case N-640, "Alternative Reference Fracture Toughness for Development of P-T Limit Curves [ASME Code] Section XI, Division 1."

Reflood Thermal Shock Analysis

The applicant has reviewed the reflood thermal shock analysis for Peach Bottom. For the reflood thermal shock event, the peak stress intensity at 1/4 of vessel thickness from inside occurs at about 300 seconds after the LOCA. At 300 seconds, the analysis shows that the temperature of the vessel wall at a depth of 38.1 mm (1.5 inches) is approximately 204 °C (400 °F). The applicant expects that the vessel beltline material ART, even after 60 years of irradiation, will be low enough to ensure that the material is in the Charpy upper shelf region at 204 °C. Therefore, the analysis will be bounding and valid for the license renewal term.

Charpy Upper Shelf Energy (USE)

By letter dated April 30, 1993, the Boiling Water Reactor Owners Group (BWROG) submitted a topical report entitled "10 CFR Part 50 Appendix G Equivalent Margins Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels," to demonstrate that BWR RPVs could meet margins of safety against fracture equivalent to those required by Appendix G of the ASME

Code Section XI for Charpy USE values less than 68 J (50 ft-lb). General Electric (GE) performed an update to the USE equivalent margins analysis, which is documented in EPRI TR-113596, "BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," BWRVIP-74, September 1999. This updated analysis incorporates the effects of irradiation for 54 effective full-power years (EFPYs), which corresponds to 60 years of operation at 90% power. The updated analysis determined that the generic materials considered would maintain the margins for USE required by 10 CFR Part 50 Appendix G. The application indicates that the applicant plans to review the generic analyses with respect to their applicability for the Peach Bottom license renewal term. This review will determine whether the generic analyses are applicable and whether the critical materials would retain sufficient USE to satisfy 10 CFR Part 50 Appendix G requirements for 54 EFPYs. The applicant plans to complete this review and confirm the acceptable value for USE before the end of the initial operating license term for Peach Bottom.

4.2.1.2 Staff Evaluation

Neutron Irradiation Embrittlement

Appendix G to 10 CFR Part 50 specifies fracture toughness requirements for ferritic materials of the pressure-retaining components of the reactor coolant pressure boundary of light water nuclear power reactors to ensure adequate margins of safety during any condition of normal operation, including anticipated operational occurrences and system hydrostatic tests, to which the pressure boundary may be subjected over its service lifetime. For the RPV, this appendix requires an evaluation of the Charpy USE and an evaluation of the ART to determine pressure-temperature limits for the RPV. Neutron irradiation causes a decrease in the Charpy USE and an increase in the ART of the RPV beltline materials. The staff's evaluation of the impact of irradiation on the reflood thermal shock analysis and Charpy USE is discussed in this section. The staff's evaluation of the impact of irradiation on pressure-temperature limit, RPV circumferential weld, and RPV axial weld integrity analyses is discussed in SER Sections 4.2.2.2, 4.2.3.2, and 4.2.4.2, respectively. Since each of these evaluations depends on the neutron fluence received by the RPV, neutron fluence is also discussed in these sections.

Neutron Fluence and RT_{NDT}

The RT_{NDT}, reflood thermal shock analysis, Charpy USE, P-T limit, circumferential weld, and axial weld integrity evaluations are all dependent upon the neutron fluence. The applicant states that it will initiate the calculations for end-of-life fluence for a 60-year licensed operating period (54 EFPYs) using the GE fluence calculation methodology (NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation") after the NRC approves it.

In order to determine whether neutron irradiation embrittlement will satisfy the time-limited aging analysis criterion in 10 CFR Part 54.21(c)(1), the staff issued RAI 4.2-1 requesting the applicant to determine the adjusted reference temperature (ART) and the Charpy upper shelf energy (USE) at the end of the license renewal period (60 years of operation). These analyses require that the applicant determine the peak neutron fluence at the end of the license renewal period. Therefore, in RAI 4.2-1, the staff also requested the applicant to calculate the peak neutron fluence at the clad-steel interface and the 1/4 thickness (1/4T) location in the reactor vessels at the end of the license renewal period using a methodology approved by the staff and adhering to the guidance in Regulatory Guide (RG) 1.190,"Calculation and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence."

In response to RAI 4.2-1, the applicant submitted the following estimates of neutron fluence and adjusted reference temperature for Peach Bottom Units 2 and 3. The applicant response for estimates of upper shelf energy is presented later in this section under the heading Charpy upper shelf energy (USE).

Neutron fluence: For Units 2 and 3, the 54 EFPYs RPV peak fluence predictions are 2.2 x 10^{18} n/cm^2 at the inner vessel wall and 1.6 x 10^{18} n/cm^2 at 1/4T location. The neutron fluence calculation was performed using the methodology of NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation," which was approved by the NRC in a letter dated September 14, 2001, from S.A. Richards (NRC) to J.F. Klapproth (GE). Since the neutron fluence evaluation was performed in accordance with a methodology that was approved by the staff, the results are acceptable and may be utilized for the evaluations discussed in SER Sections 4.2.2.2, 4.2.3.2, and 4.2.4.2.

The ART is defined as the sum of the initial (unirradiated) reference temperature (initial RT_{NDT}), the mean value of the adjustment in reference temperature caused by irradiation (delta RT_{NDT}), and a margin (M) term. The delta RT_{NDT} is a product of a chemistry factor and a fluence factor. The chemistry factor is dependent upon the amount of copper and nickel in the material and may be determined from tables in RG 1.99, Rev. 2, or from surveillance data. The fluence factor is dependent upon the neutron fluence at the maximum postulated flaw depth. The margin term is dependent upon whether the initial RT_{NDT} is a plant-specific or a generic value and whether the chemistry factor (CF) was determined using the tables in RG 1.99, Rev. 2, or surveillance data. The margin term is used to account for uncertainties in the values of the initial RT_{NDT}, the copper and nickel contents, the fluence, and the calculation methods. RG 1.99, Rev. 2, describes the methodology to be used in calculating the margin term.

The 54 EFPYs ART for the limiting beltline material for Unit 2 (Shell # 2 Heat C2873-1) at 1/4T is 70 °F. The 54 EFPYs ART for the limiting material for Unit 3 (Shell # 2, Heat C2773-2) at 1/4T is 97 °F. These values for ARTs were confirmed by the staff using the neutron fluence value of 1.6E18 n/cm^2, the initial RT_{NDT} values, and the Cu and Ni contents for the limiting beltline materials from the Peach Bottom Updated Final Safety Analysis Report, Volume 1. The Cu and Ni contents for the limiting beltline material are 0.12 and 0.57 wt%, respectively, for Unit 2, and 0.15 and 0.49 wt%, respectively, for Unit 3. The initial RT_{NDT} for the limiting beltline material is -6 °F for Unit 2 and 10 °F for Unit 3. A margin value of 34 °F was used for confirming the ARTs. The staff finds the ART consistent with RG 1.99, Revision 2, and acceptable.

<u>Reflood Thermal Shock Analysis</u>

The applicant has reviewed the reflood thermal shock analysis for Peach Bottom. For the reflood thermal shock event, the peak stress intensity at 1/4 of vessel thickness from inside occurs about 300 seconds after the LOCA. At 300 seconds, the analysis shows that the temperature of the vessel wall at a depth of 38.1mm (1.5 inches) is approximately 204 °C (400 °F). The applicant states that the reflood thermal shock analysis for 40-years of operation (32 EFPYs) will be bounding and valid for the license renewal term because the vessel beltline material ART, even after 60 years of irradiation, is expected to be low enough to ensure that the material is in the Charpy upper shelf region at 204 °C. In RAI 4.2-2, the staff requested the applicant to present the technical basis for expecting the vessel beltline material ART after 60 years of irradiation to be low enough so that the material is in the Charpy upper shelf region at 204 °C. In response, the applicant referred to its response to RAI 4.2-1, which indicated that the ART for the limiting plate material for Peach Bottom Unit 2 is 70 °F and for Unit 3 is 97 °F, which is well below the 204 °C (400 °F) 1/4T temperature predicted for the thermal shock event at the time of peak stress intensity. The reflood thermal shock analysis is, therefore, bounding and valid for the license renewal term.

Charpy Upper Shelf Energy (USE)

Section IV.A.1a of Appendix G to 10 CFR Part 50 requires, in part, that the RPV beltline materials have Charpy USE in the transverse direction for base metal and along the weld for weld material of no less than 50 ft-lb (68J), unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will ensure margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

By letter dated April 30, 1993, the Boiling Water Reactor Owners Group (BWROG) submitted a topical report entitled "10 CFR Part 50 Appendix G Equivalent Margins Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels," to demonstrate that BWR RPVs could meet margins of safety against fracture equivalent to those required by Appendix G of the ASME Code Section XI for Charpy USE values less than 50 ft-lb. In a letter dated December 8, 1993, the staff concluded that the topical report demonstrates that the evaluated materials have the margins of safety against fracture equivalent to Appendix G of ASME Code Section XI, in accordance with Appendix G of 10 CFR Part 50. In this report, the BWROG derived through statistical analysis the unirradiated USE values for materials that originally did not have documented unirradiated Charpy USE values. Using these statistically derived Charpy USE values, the BWROG predicted the end-of life (40 years of operation) USE values in accordance with RG 1.99, Rev. 2. According to this RG, the decrease in USE is dependent upon the amount of copper in the material and the neutron fluence predicted for the material. The BWROG analysis determined that the minimum allowable Charpy USE in the transverse direction for base metal and along the weld for weld metal was 35 ft-lb.

General Electric (GE) performed an update to the USE equivalent margins analysis, which is documented in EPRI TR-113596, "BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," BWRVIP-74, September 1999. The staff review and approval of EPRI TR-113596 is documented in a letter from C. I. Grimes to C. Terry dated October 18, 2001. The analysis in EPRI TR-113596 determined the reduction in the unirradiated Charpy USE resulting from neutron radiation using the methodology in RG 1.99, Revision 2. Using this methodology and a correction factor of 65% for conversion of the longitudinal properties to transverse properties, the lowest irradiated Charpy USE at 54 EFPYs for all BWR/3-6 plates is projected to be 45 ft-lb. The correction factor for specimen orientation in plates is based on NRC Branch Technical position MTEB 5-2. Using the RG methodology, the lowest irradiated Charpy USE at 54 EFPY for BWR non-Linde 80 submerged arc welds is projected to be 43 ft-lb. EPRI TR-113596 indicates that the percent reduction in Charpy USE for the limiting BWR/3-6 beltline plates and BWR non-Linde 80 submerged arc welds are 23.5% and 39%, respectively. Since this is a generic analysis, the staff issued RAI 4.2-3 requesting the applicant to submit plant-specific information to demonstrate that the beltline materials of the Peach Bottom Units 2 and 3 RPVs meet the criteria in the report at the end of the license renewal period. The applicant was specifically requested to submit the information specified in Tables B-4 and B-5 of EPRI TR-113596. In response to RAI 4.2-3, the applicant stated that the predicted percent decrease of the beltline material USE values at 1/4T and 54 EFPYs was estimated using BWRVIP-74 and RG 1.99, Revision 2. The equivalent margin analysis was performed using information presented in Tables B-4 and B-5 of EPRI TR-113596. RG 1.99, Revision 2, predicted percent decrease in USE for the limiting beltline plate material at the end of the license renewal period is 14% for Unit 2 and 16% for Unit 3; both predicted values of USE are less than the generic value of 23.5% reported in EPRI TR-113596. Similarly, the RG 1.99, Revision 2, predicted percent decrease in USE for limiting weld material (non-Linde 80 weld material at both units) at the end of license renewal period is 21% for both Unit 2 and Unit 3, which is less than the generic value of 39% reported in EPRI TR-113596. The predicted values for the decrease in USE for limiting beltline weld and plate materials for Units 2 and 3 were confirmed by the staff using the 54 EFPYs neutron fluence values at 1/4T provided by the applicant and the values of the Cu contents for the limiting materials from the Peach Bottom Updated Final Safety Analysis Report, Volume 1. The 54 EFPYs neutron fluence at 1/4T for the limiting beltline plate and weld materials of both units is 1.6E18 n/cm^2. The Cu contents for the limiting beltline materials are 0.182 wt% for weld and 0.13 wt% for plate for Unit 2, and 0.182 wt% for weld and 0.15 wt% for plate for Unit 3. The staff finds the applicant response acceptable because the percent decrease in USE for plant-specific limiting plate and weld materials at Units 2 and 3 is bounded by the corresponding generic results obtained by the equivalent margin analysis presented in EPRI TR-113596 as mentioned above. Therefore, the Charpy USE values at 54 EFPYs for the limiting plate and weld materials at Units 2 and 3 are greater than the minimum allowable value of 35 ft-lb, which demonstrates that the evaluated materials have the margins of safety against fracture equivalent to Appendix G of Section XI of the ASME Code, in accordance with Appendix G of 10 CFR Part 50, throughout the license renewal period. The UFSAR Supplement needs to include the additional information contained in the applicant's response to RAI 4.2-3 regarding the evaluation of this TLAA. In a letter dated November 26, 2002, responding to this Confirmatory Item, the applicant provided a revision to Section A.5.1.1 of the UFSAR Supplement, which describes the USE analyses performed by the applicant, and adequately addresses the issue.

4.2.1.3 Conclusions

The staff has reviewed the information in LRA Section 4.2.1, "10 CFR 50 Appendix G Reactor Vessel Rapid Failure Propagation and Brittle Fracture Considerations: Charpy Upper Shelf Energy (USE) Reduction and RT_{NDT} Increase, Reflood Thermal Shock Analysis." On the basis of this review, the staff concludes that the applicant has adequately evaluated the TLAA related to 10 CFR Part 50 Appendix G reactor vessel rapid failure propagation and brittle fracture considerations (Charpy upper shelf energy (USE) reduction, RT_{NDT} increase, and reflood thermal shock analysis), as required by 10 CFR 54.21(c)(1)(i). The staff has also reviewed the UFSAR Supplement and the staff concludes that, the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.2.2 Reactor Vessel Thermal Analyses: Operating Pressure-Temperature Limit (P-T Limit) Curves

4.2.2.1 Summary of Technical Information in the Application

Peach Bottom Technical Specification 3.4.9 presents P-T limit curves for heatup and cooldown, and also limit the maximum rate of change of reactor coolant temperature. At Peach Bottom, the criticality curve presents limits for both heatup and criticality are calculated for a 40-year design (32 EFPY). The application indicates that the applicant will determine the P-T limits for 60 years (54 EFPY), in accordance with 10 CFR 54.21(c)(1)(ii), after the GE fluence methodology has been approved by the NRC.

4.2.2.2 Staff Evaluation

The P-T limit curves are based on the following NRC regulations and guidance: 10 CFR Part 50, Appendix G; Generic Letter (GL) 88-11, "NRC Position on Radiation Embrittlement of Reactor Vessel Materials and Its Impact on Plant Operations"; GL 92-01, "Reactor Vessel Structural Integrity, " Revision 1; GL 92-01, Revision 1, Supplement 1; RG 1.99, Revision 2; and Standard Review Plan (SRP) Section 5.3.2, "Pressure-Temperature Limits and Pressurized Thermal Shock." GL 88-11 advised applicants that the staff would use RG 1.99, Revision 2, to review P-T limit curves. RG 1.99, Revision 2, contains methodologies for determining the increase in transition temperature and the decrease in upper shelf energy resulting from neutron radiation. GL 92-01, Revision 1, requested that applicants submit their RPV data for their plants to the staff for review. GL 92-01, Revision 1, Supplement 1, requested that applicants submit and assess data from other applicants that could affect their RPV integrity evaluations. These data are used by the staff as the basis for the staff's review of P-T limit curves. Appendix G to 10 CFR Part 50 requires that P-T limit curves for the RPV be at least as conservative as those obtained by the methodology of Appendix G Section XI of the ASME Code.

SRP Section 5.3.2 presents an acceptable method of determining the P-T limit curves for ferritic materials in the beltline of the RPV based on the linear elastic fracture mechanics (LEFM) methodology of Appendix G to Section XI of the ASME Code. The basic parameter of this methodology is the stress intensity factor K_I, which is a function of the stress state and flaw configuration. Appendix G requires a safety factor of 2.0 on stress intensities resulting from reactor pressure during normal and transient operating conditions and a safety factor of 1.5 for hydrostatic testing curves. The methods of Appendix G postulate the existence of a sharp surface flaw in the RPV that is normal to the direction of the maximum stress. This flaw is postulated to have a depth that is equal to 1/4 the thickness (1/4T) of the RPV beltline thickness and a length equal to 1.5 times the RPV beltline thickness. The critical locations in the RPV beltline region for calculating cooldown and heatup P-T limit curves are the 1/4T and 3/4 thickness (3/4T) locations, which correspond to the maximum depth of the postulated inside surface and outside surface defects, respectively. The ASME Code Appendix G methodology requires that applicants determine the ART at the end of the operating period.

The applicant plans to calculate vessel P-T limit curves for 60 years (54 EFPYs) after the NRC has approved GE fluence calculation methodology. As discussed in Section 4.2.1.2 of the SE, the staff has approved the GE fluence calculation methodology that is documented in topical report NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation." This topical report was approved by the NRC in a letter dated September 14, 2001 from S.A. Richards (NRC) to J.F. Klapproth (GE). In RAI 4.2-5, the staff requested the applicant to submit P-T limit curves for a 60-year (54 EFPYs) design for Peach Bottom using the GE methodology. In response, the applicant stated that the vessel P-T limit curves for 54 EFPYs have been completed. The plant technical specifications will be modified to incorporate these P-T limit curves when the current curves reach their operational limits. The curves will be submitted to the NRC as a license amendment prior to the end of the initial operating license term for Peach Bottom. The staff finds the applicant's response acceptable because the change in P-T curves will be implemented by the license amendment process.

4.2.2.3 Conclusions

The staff has reviewed the information in LRA Section 4.2.2, "Reactor Vessel Thermal Limit Analyses: Operating Pressure-Temperature Limit (P-T Limit) Curves." On the basis of this review, the staff concludes that the applicant has adequately evaluated the reactor vessel operating pressure-temperature limit curves TLAA, as required by 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.2.3 Reactor Vessel Circumferential Weld Examination Relief

4.2.3.1 Summary of Technical Information in the Application

Sections 4.2.3 and A.5.1.2 of the LRA discuss inspection of the Peach Bottom RPV circumferential welds. These sections of the LRA indicate that Peach Bottom will use an approved technical alternative in lieu of ultrasonic testing of RPV circumferential shell welds. The BWRVIP presented the technical bases in EPRI TR-113596 for supporting the elimination of RPV circumferential welds from the inservice inspection programs for BWRs. These technical bases are approved for the current license term and are applicable to Peach Bottom.

Appendix E of the NRC's safety evaluation report (SER), "Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report " USNRC, July 28, 1998, documents an evaluation of the impact of license renewal from 32 to 64 EFPYs on the conditional probability of vessel failure. The SER reports that the frequency of cold overpressurization events results in a total vessel failure probability of approximately 5×10^{-7}. The SER conservatively evaluates an operating period of 10 EFPYs greater than what is realistically expected for a 20-year license renewal term, i.e., 48 to 54 EFPYs. Therefore, this analysis supplies a basis for BWRVIP-05 to be approved as a technical alternative from the current inservice inspection requirements of ASME Section XI for volumetric examination of the circumferential welds as they may apply in the license renewal period.

In LRA Section 4.2.3, "Reactor Vessel Circumferential Weld Examination Relief," the applicant states that the procedures and training used to limit the frequency of cold overpressure events to the specified number in the current licensed operating period will also be used during the license renewal term. The applicant will apply for an extension of the subject relief for the 60-year extended licensed operating period prior to the end of the initial operating license term for Peach Bottom.

4.2.3.2 Staff Evaluation

Sections 4.2.3 and A.5.1.2 of the LRA discuss inspection of the Peach Bottom RPV circumferential welds. These sections of the LRA indicate that Peach Bottom will use an approved technical alternative in lieu of ultrasonic testing of RPV circumferential shell welds.

The technical alternative is discussed in the staff's final SER of the BWRVIP-05 report, which is enclosed in a July 28, 1998 letter to Carl Terry, BWRVIP Chairman. In this letter, the staff concludes that since the failure frequency for circumferential welds in BWR plants is significantly below the criterion specified in RG 1.154, "Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors," and the core damage frequency (CDF) of any BWR plant, since that continued inspection would result in a negligible decrease in an already acceptably low value, elimination of the ISI for RPV circumferential welds is justified. The staff's letter indicated that BWR applicants may request relief from inservice inspection requirements of 10 CFR 50.55a(g) for volumetric examination of circumferential RPV welds by demonstrating that (1) at the expiration of the license, the circumferential welds satisfy the limiting conditional failure probability for circumferential welds in the evaluation, and (2) the applicants have implemented operator training and established procedures that limit the frequency of cold over-pressure events to the frequency specified in the report. The letter indicated that the requirements for inspection of circumferential RPV welds during an additional 20-year license renewal period would be reassessed, on a plant specific basis, as part of any BWR LRA.

Section A.4.5 of report BWRVIP 74 indicates that the staff's SER conservatively evaluated the BWR RPVs to 64 effective full power years (EFPYs), which is 10 EFPYs greater than what is realistically expected for the end of the license renewal period. Since this was a generic analysis, the staff issued RAI 4.2-6 requesting the applicant to submit plant-specific information to demonstrate that the Peach Bottom beltline materials meet the criteria specified in the report. To demonstrate that the vessel has not become embrittled beyond the basis for the technical alternative, the applicant must supply (1) a comparison of the neutron fluence, initial RT_{NDT}, chemistry factor, amounts of copper and nickel, delta RT_{NDT} and mean RT_{NDT} of the limiting circumferential weld at the end of the renewal period to the 64 EFPYs reference case in Appendix E of the staff's SER, and (2) an estimate of conditional failure probability of the RPV at the end of the license renewal term based on the comparison of the mean RT_{NDT} for the limiting circumferential weld and the reference case. Should the applicant request relief from augmented ISI requirements for volumetric examination of circumferential RPV welds during the period of extended operation, the applicant is requested to demonstrate that (1) at the expiration of the license, the circumferential welds satisfy the limiting conditional failure probability for circumferential welds in the evaluation, and (2) the applicant has implemented operator training and established procedures that limit the frequency of cold overpressure events to the frequency specified in the report. In response to the RAI, the applicant compared the limiting circumferential weld properties for Peach Bottom Units 2 and 3 to the information in Table 2.6-4 and Table 2.6-5 of the staff SER on BWRVIP-05 dated July 28, 1998.

The NRC staff used the mean RT_{NDT} value for materials to evaluate failure probability of BWR circumferential welds at 32 and 64 EFPYs in the staff SER dated July 28, 1998. The mean RT_{NDT} value is defined as the sum of the initial (unirradiated) reference temperature (initial RT_{NDT}) and the mean value of the adjustment in reference temperature caused by irradiation (delta RT_{NDT}); it does not include a margin (M). The neutron fluence used in this evaluation was the neutron fluence clad-weld (inner) interface. The mean RT_{NDT} for Peach Bottom Units 2 and 3 is determined to provide a comparison with the values documented in the staff SER. The 54 EFPYs mean RT_{NDT} values thus determined are12 °F and 17 °F for Units 2 and 3, respectively. The staff confirmed these values of mean RT_{NDT} using the data for 54 EFPYs neutron fluence at the clad-weld interface provided by the applicant and the data for Ni and Cu contents in the girth welds from the Peach Bottom Updated Final Safety Analysis Report, Volume 1. For Unit 2, the 54 EFPYs fluence is 1.8E18 n/cm^2, and Cu and Ni contents are 0.056 and 0.96 wt%, respectively. For Unit 3, the 54 EFPYs fluence is 1.4E18 n/cm^2, and Cu and Ni contents are 0.102 and 0.942 wt%. These 54 EFPYs values mean that RT_{NDT} values for Units 2 and 3 are bounded by the 64 EFPYs mean RT_{NDT} value of 70.6 °F used by NRC for determining the conditional failure probability of a circumferential girth weld. The 64 EFPYs mean RT_{NDT} value from the staff SER dated July 28, 1998, is for a Chicago Bridge and Iron (CB&I) weld because CB&I welded the girth welds in the Peach Bottom vessels. Since the Peach Bottom 54 EFPYs value is less than the 64 EFPYs value from the staff SER dated July 28, 1998, the staff concludes that the Peach Bottom RPV conditional failure probability is bounded by the NRC analysis.

The procedures and training used to limit cold overpressure events will be the same those approved by the NRC when Peach Bottom requested to use the BWRVIP-05 technical alternative for the current term (letter from James Hutton of PECO Nuclear to NRC dated February 7, 2000). The staff find the applicant's response to RAI 4.2-6 acceptable because the 54 EFPYs mean RT_{NDT} value for the circumferential weld is bounded by the NRC analysis in the staff SER dated July 28, 1998, and Peach Bottom will be using procedures and training to limit cold overpressure events during the period of extended operation. The UFSAR Supplement needs to include the additional information contained in the applicant's response to RAI 4.2-6 regarding the evaluation of this TLAA. In a letter dated November 26, 2002, responding to this Confirmatory Item, the applicant provided a revision to Section A.5.1.1.3 of the UFSAR Supplement, which describes the analysis of the circumferential welds and adequately addresses this issue.

4.2.3.3 Conclusions

The staff has reviewed the information in LRA Section 4.2.3, "Reactor Vessel Circumferential Weld Examination Relief." On the basis of this review, the staff concludes that the applicant has adequately evaluated the reactor vessel circumferential weld examination relief TLAA, as required by 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes that, the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.2.4 Reactor Vessel Axial Weld Failure Probability

4.2.4.1 Summary of Technical Information in the Application

The staff's SER, enclosed in a letter dated March 7, 2000, to Carl Terry, BWRVIP Chairman, discusses the failure frequency for RPV axial welds and the BWRVIP analysis of the RPV failure frequency for axial welds. The SER indicates that the RPV failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 years of operation is below 5 x 10^{-6} per reactor year, given the assumptions on flaw density, distribution, and location described in this SER. Since the BWRVIP analysis was generic, the applicant plans to perform plant-specific analyses to confirm that the axial weld failure probability for the Peach Bottom RPVs remains below 5 x 10^{-6} per reactor year during the period of extended operation, in accordance with 10 CFR Part 54.21(c)(1)(i). The application indicates that the applicant plans to complete these analyses prior to the end of the initial operating license term for Peach Bottom.

4.2.4.2 Staff Evaluation

In its July 28, 1998, letter to Carl Terry, BWRVIP Chairman, the staff identified a concern about the failure frequency of axially oriented welds in BWR RPVs. In response to this concern, the BWRVIP supplied evaluations of axial weld failure frequency in letters dated December 15, 1998, and November 12, 1999. The staff's SER on these analyses is enclosed in a March 7, 2000 letter to Carl Terry. The SER indicates that the RPV failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 years of operation is below 5×10^{-6} per reactor year, given the assumptions on flaw density, distribution, and location described in this SER. Since the results apply only for the initial 40-year license period of BWR plants, applicants for license renewal must submit plant-specific information applicable to 60 years of operation.

The BWRVIP identified the Clinton and Pilgrim reactor vessels as the reactor vessels with the highest mean RT_{NDT} in the BWR fleet. The staff confirmed this conclusion in the SER enclosed in the March 7, 2000, letter by comparing the information in the BWRVIP analysis and the information in the Reactor Vessel Integrity Database (RVID) for all BWR RPV axial welds. The results of the staff calculations are presented in Table 1. The staff calculations used the basic input information for Pilgrim, with three different assumptions for the initial RT_{NDT}. The calculations of the actual Pilgrim condition used the docketed initial RT_{NDT} of -44 °C (-48 °F) and a mean RT_{NDT} of 20 °C (68 °F). A second calculation, listed as "Mod 1" in Table 1, uses an initial RT_{NDT} of -18 °C (0 °F) and a mean RT_{NDT} of 47 °C (116 °F) consistent with the BWRVIP calculations. A third calculation, with an initial RT_{NDT} of -19 °C (-2 °F) and a mean RT_{NDT} of 46 °C (114 °F), was chosen to identify the mean value of RT_{NDT} required to provide a result which closely matches the RPV failure frequency of 5×10^{-6} per reactor-year.

Table 1: Comparison of Results from Staff and BWRVIP

Plant	Initial RT_{NDT} (°F)*	Mean RT_{NDT} (°F)	Vessel Failure Freq.	
			Staff	BWRVIP
Clinton	-30	91	2.73E-6	1.52E-6
Pilgrim	-48	68	2.24E-7	-------
Mod 1 **	0	116	5.51E-6	1.55E-6
Mod 2 ***	-2	114	5.02E-6	-------

* °C = 0.56 x (°F – 32)

** A variant of Pilgrim input data, with initial RT_{NDT} = 0 °F.

*** A variant of Pilgrim input data, with initial RT_{NDT} = -2 °F.

Since the BWRVIP analysis was generic, the staff issued RAI 4.2-7 requesting the applicant to submit plant-specific information to demonstrate that the Peach Bottom beltline materials meet the criteria specified in the report. To demonstrate that the vessel has not become embrittled beyond the basis for the staff and BWRVIP analyses, the applicant was requested to submit (1) a comparison of the neutron fluence, initial RT_{NDT}, chemistry factor, amounts of copper and nickel, delta RT_{NDT}, and mean RT_{NDT} of the limiting axial weld at the end of the renewal period to the reference cases in the BWRVIP and staff analyses; and (2) an estimate of the conditional failure probability of the RPV at the end of the license renewal term based on the comparison of the mean RT_{NDT} for the limiting axial welds and the reference case. If this comparison does not indicate that the RPV failure frequency for axial welds is less than 5×10^{-6} per reactor year, the applicant must submit a probabilistic analysis to determine the RPV failure frequency for axial welds.

The applicant presented plant-specific information in response to RAI 4.2-7 to demonstrate that Peach Bottom beltline materials meet the criteria specified in this SER. The SER stated that the axial welds for the Clinton plant are the limiting welds for the BWR fleet, and vessel failure probability calculations determined for Clinton should bound those for the BWR fleet. The NRC used mean RT_{NDT} for the comparison. The mean RT_{NDT} values in the staff's SER were determined using the neutron fluence at the clad/weld (inner) interface, and did not include a margin term. The 54 EFPYs mean RT_{NDT} values for axial welds at clad-weld interface in both Peach Bottom Units 2 and 3 are the same and equal to 11 °F. The staff confirmed this value by using the 54 EFPYs neutron fluence data (2.2E18 n/cm^2) provided by the applicant and the data for Cu and Ni contents (0.182 and 0.181 wt%, respectively) in the axial welds from the Peach Bottom Updated Final Safety Analysis Report, Volume 1; these data are the same for the limiting beltline region axial welds for Units 2 and 3. A comparison of the mean RT_{NDT} value (91 °F) for the Clinton axial weld given in Table 1 with the Peach Bottom value (11 °F) shows that the NRC analysis of Clinton axial welds bounds the Peach Bottom axial welds. Since the Peach Bottom 54 EFPYs value is less than the Clinton value, the staff concludes that Peach Bottom is bounded by the NRC analysis that is enclosed in the March 7, 2000, letter to Carl Terry, and the staff finds the applicant's response acceptable. The UFSAR Supplement needs to include the additional information contained in the applicant's response to RAI 4.2-7 regarding the evaluation of this TLAA. In a letter dated November 26, 2002, responding to this Confirmatory Item, the applicant provided a revision to Section A.5.1.1.4 of the UFSAR Supplement, which describes the analysis of the axial welds and adequately addresses this issue.

4.2.4.3 Conclusions

The staff has reviewed the information in LRA Section 4.2, "Reactor Vessel Neutron Embrittlement." On the basis of this review, the staff concludes that the applicant has adequately evaluated the reactor vessel neutron embrittlement TLAA, as required by 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes that, the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.3 Metal Fatigue

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity as a result of metal fatigue, which initiates and propagates cracks in the material.

The fatigue life of a component is a function of its material, its environment, and the number and magnitude of the applied cyclic loads. Fatigue was a design consideration for piping and components and, consequently, fatigue is part of the current licensing basis (CLB) for Peach Bottom. The applicant identified fatigue analyses as TLAAs for piping and components. The staff reviewed Section 4.3 of the LRA, which discusses fatigue of piping and components, to determine whether the applicant has adequately evaluated the TLAAs as required by 10 CFR 54.21(c).

4.3.1 Summary of Technical Information in the Application

The applicant discussed the fatigue analyses of the Peach Bottom Unit 2 and 3 reactor pressure vessel (RPV) components in Section 4.3.1 of the LRA. The applicant indicated that the analyses have been revised to incorporate changes for power uprate and other operational changes. The applicant's revised analyses indicated that the vessel closure studs may exceed the ASME Code fatigue cumulative usage factor (CUF) limit during the current term of operation and, therefore, included the closure studs in its fatigue management program (FMP). The applicant further indicated that all RPV locations with calculated CUFs that exceed 0.4 are included in the FMP. The FMP monitors plant transients that contribute to the fatigue usage for the following components:

- RPV feedwater nozzles (Loops A and B)
- RPV support skirt
- RPV closure studs
- RPV shroud support
- RPV core spray nozzle safe end
- RPV recirculation inlet nozzle
- RPV recirculation outlet nozzle
- RPV refueling containment skirt
- RPV jet pump shroud support
- residual heat removal (RHR) return line (Loop A)
- RHR supply line (Loops A and B)
- RHR tee (Loops A and B)
- feedwater piping
- main steam piping
- torus penetrations
- torus shell

The applicant discussed the fatigue analyses of the reactor vessel internals (RVI) in Section 4.3.2.1 of the LRA. The applicant indicates that the core shroud, shroud support, and jet pump assembly evaluation were based on a standard plant design and that the core shroud supports were reevaluated to account for the effects of increased recirculation pump starts with the loop outside the thermal limits.

The applicant discussed the RVI embrittlement analysis in Section 4.3.2.2 of the LRA. The applicant's evaluation indicated that the effect of fatigue and embrittlement on end-of-life reflood thermal shock remains valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The applicant discussed the piping and component fatigue analyses in Section 4.3.3 of the LRA. The applicant designates reactor coolant pressure boundary piping as Group I piping. The applicant indicated that all Group I piping was originally designed to United States of America Standards (USAS) B31.1, 1967. This code did not require an explicit fatigue analysis of piping components. The applicant indicated that the Group I recirculation piping and RHR piping were replaced because of IGSCC concerns and that the replaced piping was analyzed to ASME Section III Class 1 requirements, which include an explicit fatigue analysis. The applicant indicated that a simplified fatigue analysis was developed for the remainder of the Group I piping to estimate CUFs from the operating data. The applicant indicated that fatigue of the Group I piping will be managed by the FMP in accordance with 10 CFR 54.21(c)(1)(iii).

The applicant designates the remainder of the safety-related piping as Group II and III. This piping was designed to the requirements of USAS B31.1. USAS B31.1 requires a reduction in the allowable bending loads if the number of full range thermal bending cycles exceeds 7,000. The applicant's evaluation indicated that the expected number of thermal bending cycles will not exceed the 7,000 limit during the period of extended operation and that the analyses remain valid for the period of extended operation in accordance with 54.21(c)(1)(i).

The applicant discussed the evaluation of the effects of the reactor coolant environment on the fatigue life of components in Section 4.3.4 of the LRA. The applicant relied on industry generic studies to address this issue.

4.3.2 Staff Evaluation

The components of the RCS were designed to codes that contained explicit criteria for fatigue analysis. Consequently, the applicant identified fatigue analyses of these RCS components as TLAAs. The staff reviewed the applicant's evaluation of the identified RCS components for compliance with the provisions of 10 CFR 54.21(c)(1).

The design criterion for ASME Class 1 components involves calculating the CUF. The fatigue damage in the component caused by each thermal or pressure transient depends on the magnitude of the stresses caused by the transient. The CUF sums the fatigue damage resulting from each transient. The design criterion is that the CUF not exceed 1.0. The applicant monitors limiting locations in the RPV, RVI, and RCS piping for fatigue usage through the FMP. The applicant relies on the FMP to monitor the CUF and manage fatigue in accordance with the provisions of 10 CFR 54.21(c)(1)(iii). The staff's evaluation of the FMP is in provided below.

The applicant indicated that all component locations where the 40-year CUFs are expected to exceed 0.4 are included in the FMP. Section 4.3.1 of this SE lists the component locations monitored by the FMP. These locations have been identified in the reactor vessel, vessel internals, reactor coolant system piping, and torus. The applicant indicated that the existing FMP maintains a count of cumulative reactor pressure vessel thermal and pressure cycles to ensure that licensing and design basis assumptions are not exceeded. The applicant also indicated that an improved program is being implemented which will use temperature, pressure, and flow data to calculate and record accumulated usage factors for critical RPV locations and subcomponents. In RAI 4.3-2, the staff requested that the applicant describe how the monitored data will be used to calculate usage factors and to indicate how the fatigue usage will be estimated prior to implementation of the improved program.

The applicant's May, 1, 2002, response indicated that the FatiguePro monitoring system will be implemented to monitor selected component locations. FatiguePro uses measured temperature, pressure, and flow data to either monitor the number of cycles of design basis transients or to directly compute the stress history to determine the actual fatigue usage for each transient. The applicant indicated that most component locations will be monitored by an automated cycle counting module that will count each licensing basis transient experienced by the plant based on input from monitored plant instruments. The applicant will incorporate the cycle counts obtained since initial plant startup for these component locations. Monitoring of the RPV feedwater nozzles and the RPV support skirt will include a fatigue usage computation based on temperature, pressure, and flow data obtained from monitored plant instruments. The applicant will estimate that the prior fatigue usage for the feedwater nozzles and the RPV support skirt assuming a linear accumulation of fatigue based on the design fatigue values. The applicant indicates that the future monitoring will be used to demonstrate the conservatism of the assumption of a linear accumulation of fatigue based on the design values. The staff considers the applicant's improved program an acceptable method to monitor fatigue of the critical components.

The applicant indicated that the closure studs are projected to have a CUF > 1.0 during the current period of operation and that the studs are included in the FMP. In RAI 4.3-1, the staff requested the applicant to provide additional discussion regarding the projected CUF for the closure studs.

The applicant's May 1, 2002, response indicated the fatigue evaluation of the reactor vessel closure studs is based on very conservative analysis techniques. The fatigue usage of the closure studs is being monitored by the FMP. The applicant indicated that corrective action will be initiated prior to reaching a CUF of 1.0 and that corrective actions would include one or more of the following options:

- refinement of the fatigue analysis to lower the CUF to below 1.0
- Repair/replacement of the studs
- manage the effects of fatigue by an inspection program

The applicant committed to provide the NRC with the inspection details of the aging management program for staff review and approval prior to implementation if the last option is selected. An aging management program under this option would be a departure from the design basis CUF evaluation described in the UFSAR Supplement, and therefore, would require a license amendment pursuant to 10 CFR 50.59. In view of the above, the staff finds the applicant's proposed corrective actions an acceptable approach to manage fatigue of the closure studs. However, in accordance with 10 CFR 54.21(d), this information needs to be added to the UFSAR Supplement, and was the subject of Confirmatory Item 4.3.2-1 discussed below.

The applicant indicated that a fatigue evaluation of the core shroud and jet pump assembly was performed for a plant where the configuration applies to Peach Bottom. The applicant further indicated that the fatigue analyses were reevaluated for the effects of increased pump starts with the loop outside thermal limits. The applicant indicated that fatigue of the critical locations of the jet pump shroud support and RPV shroud support would be managed by the FMP. In RAIs 4.3-3 and 4.3-4, the staff requested that the applicant provide further clarification regarding the revised analysis considering an increase in recirculation pump starts and its impact on the fatigue usage of the core shroud and jet pump assembly.

The applicant's May 1, 2002, response indicated that although the shroud support is not an ASME component, it was included in the original ASME Code Section III design basis evaluation for the reactor pressure vessel. The applicant further indicated that the core shroud and jet pumps are not ASME components and do not have design basis fatigue evaluations. The applicant indicated the discussion in the LRA regarding the core shroud and jet pump assembly refers to a location on the core shroud support structure where the jet pump adapter is attached.

The applicant's May 1, 2002, response also described the reevaluation of the core shroud support structure. The Peach Bottom technical specifications require that the temperature difference between an idle recirculation loop and the vessel coolant be 50 °F or less prior to pump restart. Since Peach Bottom experienced recirculation pump starts outside the technical specification limit, a reevaluation was triggered. The applicant accounted for the fatigue associated with these events by using the results from the design basis sudden pump start event. The design basis sudden pump start is a more severe thermal transient than the events that have occurred at Peach Bottom. The calculated fatigue usage from the design basis event is multiplied by the ratio of the temperature difference from the actual pump start to the temperature from the design basis event to obtain the fatigue usage for each pump start event at Peach Bottom. The applicant provided the results from a sample calculation to demonstrate the conservatism of the procedure. On the basis of the results of the applicant's sample calculation, the staff finds the applicant's evaluation provides an acceptable method to estimate the fatigue usage resulting from the recirculation pump start events experienced at Peach Bottom.

The applicant's FMP tracks transients and cycles of RCS components that have explicit design basis transient cycles to ensure that these components stay within their design basis. Generic Safety Issue (GSI) 166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of these components. Although GSI-166 was resolved for the current 40-year design life of operating plants, the staff initiated GSI-190 to address license renewal. The resolution of GSI-166 for the 40-year design life relied, in part, on conservatism in the existing CLB analyses. This conservatism included the number and magnitude of the cyclic loads postulated in the initial component design. Although GSI-166 was resolved for the current 40-year design life of operating components, the staff identified GSI-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life," to address license renewal. The NRC closed GSI-190 in December, 1999, concluding:

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (NEI and EPRI), and the different approaches available to the licensees to mange the effects of aging, lead to the conclusion that no generic regulatory action is required, and that GSI-190 is closed. This conclusion is based primarily on the negligible calculated increases in core damage frequency in going from 40 to 60 year lives. However, the calculations supporting resolution of this issue, which included consideration of environmental effects, and the nature of age-related degradation indicate the potential for an increase in the frequency of pipe breaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in

10 CFR 54.21, licensees should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

The applicant indicated that there is sufficient conservatism in the fatigue analyses of components at Peach Bottom to account for the effects of the environment on the design fatigue curves. The applicant relied on the results of generic industry studies to support this argument. The staff has previously commented on these generic industry studies.

By letter dated February 9, 1998, the Electric Power Research Institute (EPRI) submitted two technical reports dealing with the fatigue issue. EPRI topical reports TR-107515, "Evaluation of Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal for the Calvert Cliffs Nuclear Power Plant," and TR-105759, "An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Evaluations" were part of an industry attempt to resolve GSI-190. As recommended in SECY 95-245, the EPRI analyzed components with high usage factors, using environmental fatigue data. The staff has open technical concerns regarding the EPRI reports. The staff's technical concerns were transmitted to the Nuclear Energy Institute (NEI) by letter dated November 2, 1998, and NEI responded to the staff's concerns in a letter dated April 8, 1999. The staff submitted its assessment of the response in a letter to NEI, dated August 6, 1999. As indicated in the staff's letter, the NEI response did not resolve all of the staff's technical concerns regarding the EPRI reports.

Although the letter dated August 6, 1999, identified the staff's concerns regarding the EPRI procedure and its application to PWRs, the technical concerns regarding the application of the Argonne National Laboratory (ANL) statistical correlations and strain threshold values are also relevant to BWRs. In addition to the concerns referenced above, the staff identified additional concerns regarding the applicability of the EPRI BWR studies in its review of the Hatch LRA. EPRI topical report TR-107943, "Environmental Fatigue Evaluations of Representative BWR Components," addressed a BWR-6 plant, and EPRI topical report TR-110356, "Evaluation of Environmental Thermal Fatigue Effects on Selected Components in a Boiling Water Reactor Plant," used plant transient data from a newer vintage BWR-4 plant. The applicant indicated that these issues were considered in the assessment of metal fatigue at Peach Bottom.

The applicant discussed the impact of the environmental correction factors for carbon and low-alloy steels contained in NUREG/CR-6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," and the environmental correction factors for austenitic stainless steels contained in NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design of Austenitic Stainless Steels," on the results of the EPRI studies. The applicant indicated that the impact of the new carbon steel data was not significant. The applicant applied a correction factor of 2.0 to the EPRI generic study results to account for the new stainless steel data.

The applicant indicated that EPRI topical report TR-110356 contained studies that are directly applicable to Peach Bottom because they involved a BWR-4 that is identical to the Peach Bottom design. However, the only components evaluated in TR-110356 are the feedwater nozzle and the control rod drive penetration locations. The staff had previously expressed concerns regarding the applicability of the measured data contained in EPRI topical report TR-110356 to another facility in its review of the Hatch LRA.

The applicant provided the sixty-year CUFs projected for Peach Bottom Units 2 and 3 at the locations evaluated for an older vintage BWR in NUREG/CR-6260, "Application of NUREG/CR-5999, 'Interim Fatigue Curves to Selected Nuclear Power Plant Components'," dated March 1995, in Table 4.3.4-3 of the LRA. The applicant indicated that these locations are monitored by the FMP, and that the environmental factors have been adequately accounted for by the conservatism in the design basis transient definitions. The applicant indicated that the vessel support skirt is monitored in lieu of the shell region identified in NUREG/CR-6260 because it is a more limiting fatigue location. The applicant also indicated that, since the location is on the vessel exterior, the environmental fatigue factors do not apply. The staff agrees with the applicant's statement.

In RAI 4.3-6, the staff requested that the applicant provide an assessment of the six locations identified in NUREG/CR-6260 considering the applicable environmental fatigue correlations provided in NUREG/CR-6583 and NUREG/CR-5704 reports for Peach Bottom Units 2 and 3.

In its May 1, 2002, response, the applicant committed to perform plant-specific calculations for the locations identified in NUREG/CR-6260 for an older vintage BWR plant considering the applicable environmental factors provided in NUREG/CR-6583 and NUREG/CR-5704. The applicant committed to complete these calculations prior to the period of extended operation and take appropriate corrective actions if the resulting CUF values exceed 1.0. The staff finds the applicant's commitment to complete the plant-specific calculations described above prior to the period of extended operation acceptable. However, in accordance with 10 CFR 54.21(d), this information needs to be added to the UFSAR Supplement.

The applicant indicated that Group II and III piping systems were designed to the requirements of USAS B31.1. The applicant performed an evaluation of the number of cycles expected for the period of extended operation. The applicant's evaluation indicated that the number of cycles is expected to be substantially less than the 7,000 cycle limit during the period of extended operation. Therefore, the existing analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

The applicant indicated that the NSSS vendor specified a finite number of cycles for each of the elevated-temperature operating modes of the RHR system. The applicant also indicated that it found no description of these design operating cycles in the Peach Bottom licensing basis documents. The applicant indicated that the Group 1 RHR piping inside the drywell was analyzed to the ASME Section III Class 1 requirements. The applicant further indicated that an evaluation of the remaining Group I and Group II piping indicated that the number of thermal cycles would be substantially less the 7,000 cycle limit applicable to piping designed to USAS B31.1. In RAI 4.3-5, the staff requested the applicant to provide further clarification regarding the NSSS vendor specification.

In its May 1, 2002, response, the applicant indicated that the vendor specification contained a description of certain thermal cycles for the original system design. The applicant found no licensing basis requirements (other than design code cycle limits) like those contained in the USAS B31.1 piping design code. The applicant also stated that design to the vendor-specified cycles is not a TLAA, except as it may be included within the design code requirements. The applicant reviewed the design specifications and design codes for components such as pumps and heat exchangers to determine whether they incorporated thermal cycle design considerations. The applicant indicated that no such requirements were identified. As a consequence, the applicant concluded that the only consideration for thermal cyclic loading that needed to be considered was the USAS B31.1 cycle limit. The staff considers the applicant's clarification of this issue satisfactory.

The applicant's UFSAR Supplement for metal fatigue is provided in Section A.4 of the LRA. The applicant describes the FMP in Section A.4.2 and its assessment of metal fatigue for the reactor vessel, reactor vessel internals and piping and components in Section A.5.2. As discussed previously, the applicant indicated that corrective actions to address the fatigue of the reactor vessel closure studs would be initiated prior to the period of extended operation. With the applicant's commitment to include in the UFSAR Supplement a description of the corrective actions to address closure studs as provided above in the response to RAI 4.3-1; and perform plant specific calculations for the locations identified in NUREG/CR-6260 for an older vintage BWR plant considering applicable environmental factors provided in NUREG/CR-6583 and NUREG/CR-5704 as provided above in response to RAI RAI 4.3-6; the staff concludes that the UFSAR Supplement will include an appropriate summary description of the programs and activities to manage aging as required by 10 CFR 54.21(d). This was identified as Confirmatory Item 4.3.2-1 in the draft safety evaluation.

By letter dated November 26, 2202, responding to this Confirmatory Item, the applicant provided a revision to the UFSAR Supplement. The revised UFSAR supplement contains a description of the applicant's proposed corrective actions to address fatigue of the reactor vessel closure studs and the applicant's commitment to evaluate the impact of the reactor water environment on the fatigue life of the components identified in NUREG/CR-6260 for an older vintage BWR. On the basis of the applicant's revised UFSAR supplement, Confirmatory Item 4.3.2-1 is closed.

Fatigue Monitoring Program

Summary of Technical Information in the Application

In Appendix B.4.2 of the LRA, the applicant describes an existing aging management program, the FMP, that is designed to track cyclic and transient occurrences to ensure that reactor coolant pressure boundary components remain within ASME Code Section III fatigue limits. The applicant indicates the FMP will be enhanced to broaden its scope and update its implementation methods. The applicant further indicates that the program will use a computerized data acquisition, recording and tracking system.

Staff Evaluation

The staff's evaluation of the FMP focused on how the program manages fatigue through effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls and operating experience.

The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site controlled corrective actions program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to aging management review. The staff evaluation of the applicant's corrective actions program is provided separately in Section 3.0.4 of this SER. The corrective actions program satisfies the elements of corrective actions, confirmation process, and administrative controls. The remaining 7 elements are discussed below.

Program Scope: The scope of the program includes the reactor pressure vessel (RPV), reactor vessel internals (RVI), Group I piping reactor coolant pressure boundary and the torus structure. The staff considers the scope of the FMP, which includes components, including components of the reactor coolant pressure boundary, with fatigue analyses, to be acceptable.

Preventive and Mitigative Actions: The applicant referred to the cycle counting procedure as the preventative action for this program. The staff did not identify a need for any additional preventive or mitigative actions.

Parameters Inspected or Monitored: The applicant monitors the transients that contribute to the fatigue usage of the components discussed in Section 4.3 of the SE. The staff finds that monitoring these selected high fatigue usage locations provides an acceptable method to monitor the fatigue usage due to design transients for the RPV, RVI, Group 1 reactor coolant pressure boundary piping, and torus structure.

Detection of Aging Effects: The program continuously monitors operational transients and updates the fatigue analyses of the monitored components . This provides assurance that the fatigue analyses of record remain valid during the period of extended operation. The staff finds this monitoring acceptable.

Monitoring and Trending: As stated previously, the program continuously monitors the operational transients that contribute to the fatigue usage of the monitored components to assure that the fatigue analyses of record remain valid during the period of extended operation. The staff finds that the applicant's continuous monitoring is sufficient to allow for timely corrective actions and is, therefore, acceptable.

Acceptance Criteria: The acceptance criteria consists of maintaining the fatigue usage below the code limit. By meeting these limits, the applicant provides assurance that the monitored components remain within their design limits. Therefore, the staff considers this criteria acceptable.

Operating Experience: The applicant's program was developed in response to concerns that early-life operating cycles at some units caused fatigue usage to accumulate faster than anticipated in the design analysis. The applicant has selected a sample of critical locations to monitor the fatigue usage accumulation. The staff finds that the applicant has adequately considered operating experience in selecting the locations to be monitored.

The staff reviewed Section A.4.2 of the UFSAR Supplement (Appendix A of the LRA) to verify that the information provided in the UFSAR Supplement for the aging management associated with the FMP is equivalent to the information in NUREG-1800. The staff concludes that the UFSAR Supplement provides an adequate summary of program activities as required by 10 CFR 54.21(d).

Conclusions

The applicant references the FMP in its discussion of the fatigue TLAAs as a program to assure that design fatigue limits are not exceeded during the period of extended operation. The staff considers the applicant's program, which monitors the number of plant transients that were assumed in the fatigue design, an acceptable method to manage the fatigue usage of the RCS components within the scope of the program. Therefore, the staff concludes that the FMP will adequately manage thermal fatigue of RCS components for the period of extended operation as required by 10 CFR 54.21(a)(3). The staff also concludes that the UFSAR Supplement contains an adequate summary description of the program activities associated with the FMP for managing the effects of aging as required by 10 CFR 54.21(d).

4.3.3 Conclusions

The staff has reviewed the information in Section 4.3 of the LRA regarding the fatigue analysis of the reactor vessel, reactor vessel internals and piping at Peach Bottom. The applicant's evaluation of Group II and III piping indicates that the analyses will remain valid for the period of extended operation. The applicant monitors the fatigue usage of critical reactor vessel, reactor vessels internals and Group I piping components using its FMP. The staff concludes that the applicant's actions and commitments satisfy the requirements of 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.4 Environmental Qualification

The 10 CFR 50.49 environmental qualification (EQ) program has been identified as a TLAA for the purposes of license renewal. The TLAA of EQ components includes all long-lived passive and active electrical and instrumentation and control (I&C) components and commodities that are located in a harsh environment and are important to safety, including safety-related and Q list equipment, non-safety-related equipment whose failure could prevent satisfactory accomplishment of any safety-related function, and the necessary post-accident monitoring equipment.

The staff has reviewed LRA Section 4.4, "Environmental Qualification of Electrical Equipmne," LRA to determine whether the applicant submitted adequate information to meet the requirements of 10 CFR 54.21(c)(1) for evaluating the EQ TLAA. Paragraph (1) of 10 CFR 54.21(c) requires that a list of EQ TLAA must be provided. The applicant must demonstrate that (i) the analyses remain valid for the period of extended operation, (ii) analyses have been projected to the end of the period of extended operation, or (iii) the effect of aging on the intended functions will be adequately managed for the period of extended operation. The staff also reviewed LRA Section 4.4.2, "GSI-168, 'Environmental Qualification of Low Voltage Instrumentation and Controls (I&C) Cables."

On the basis of this review, the staff requested additional information in a letter to the applicant dated October 26, 2001. The applicant responded to this request for additional information (RAI) in a letter to the staff dated January 2, 2002.

4.4.1 Electrical Equipment Environmental Qualification Analyses

4.4.1.1 Summary of Technical Information in the Application

The Peach Bottom EQ program complies with all applicable regulations and manages equipment thermal, radiation, and cyclic aging through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. Environmetally qualified equipment must be refurbished, replaced, or have its qualification extended prior to reaching the aging limits established in the aging evaluation. Aging evaluations for environmental qualified equipment that specify a qualified life of at least 40 years are considered TLLAs for license renewal. The following is a list of TLAAs for EQ of electrical equipment.

- GE Co. 4kV pump motors and associated cable
- EGS Grayboot connectors
- Raychem insulated splices for class 1E systems
- Bussman Co. and Gould Shawmut fuses and fuse holders
- EGS quick disconnect connectors
- Limitorque motor-operated valve actuators
- Namco position switches
- ASCO solenoid valves, trip coils, and pressure switches
- UCI splice tape
- Rosemount 1153 Series B transmitters
- GE Co. control station
- Agastat relays
- static O-ring pressure switches
- Cutler Hammer motor control centers
- NDT International accoustical monitors
- Target Rock solenoid valves
- PYCO Resistance Temperature Detectors (RTDs) and thermocouples
- ITT Barton differential pressure switches
- Atkomatic solenoid valves
- Reliance fan motors and SGTS auxiliaries
- Brown Boveri load centers
- Valcor solenoid valves
- GE Co. radiation elements
- Pyle National plug connectors
- General Atomic radiation monitors
- GE electrical penetrations
- Buchanan terminal blocks
- GE terminal blocks
- Marathon terminal blocks
- Weidmueller terminal blocks
- Amp Inc. terminal lugs
- Scotch insulating tape
- GE SIS cable
- Brand Rex cable
- ITT Suprenant 600V control cable
- Okonite 600V power and control cable
- Rockbestos cable

- Foxboro pressure transmitters
- Patel conduit seals
- Jefferson coaxial cable
- Anaconda cable
- HPCI system equipment
- Masoneilan electropneumatic transducer
- Westinghouse Y panels and associated transformers
- Barksdale pressure switches
- H_2 and O_2 analyzer
- Avco pilot solenoid valves
- Rosemout model no. 710-DU trip units
- Westinghouse manual transfer switch

The applicant states that aging effects of the EQ equipment identified in this TLAA will be managed during the extended period of operation by the EQ program activities described in Section B.4.1 of the LRA

4.4.1.2 Staff Evaluation

The staff reviewed Section 4.4.1 of the Peach Bottom LRA to determine whether the applicant submitted adequate information to meet the requirements of 10 CFR 54.21(c)(1). In addition, the staff met with the applicant to obtain clarifications and reviewed the applicant's response to the staff's request for additional information.

TLAA Demonstration for Option 10 CFR 54.21(c)(1)(iii)

For the list of electrical equipment identified in Section 4.4.1 of the LRA, the applicant uses 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that the aging effects of the EQ equipment identified in this TLAA will be managed during the extended period of operation by the EQ program activities described in Section B.4.1 of the LRA.

The staff reviewed the EQ program to determine whether it will assure that the electrical and I&C components covered under this program will continue to perform their intended function consistent with the current licensing basis for the period of extended operation. The staff's evaluation of the component qualification focused on how the program manages the aging effect through effective incorporation of the following 10 elements: program scope, preventive action, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

Program Scope: The Peach Bottom EQ program includes certain electrical components that are important to safety and could be exposed to harsh environment accident conditions, as defined in 10 CFR 50.49. The staff considers the scope of the program acceptable.

Preventive Actions: 10 CFR 50.49 does not require actions that prevent aging effects. The Peach Bottom EQ program actions that could be viewed as preventive actions include (a) establishing the component service condition tolerance and aging limits (for example, qualified life or condition limit), (b) refurbishment , replacement, or requalification of installed equipment prior to reaching these aging limits, and (c) where applicable, requiring specific installation, inspection, monitoring, or periodic maintenance actions to maintain equipment aging effects within the qualification. The staff considers these are acceptable because 10 CFR 50.49 does not require actions that prevent aging effects.

Parameter Monitored or Inspected: EQ component aging limits are not typically based on condition or performance monitoring. However, per RG 1.89 Rev. 1, such monitoring program are an acceptable basis to modify aging limits. Monitoring or inspection of certain environmental, condition or equipment monitoring may be used to ensure that the equipment is within its qualification or as a means to modify qualification. The staff considers this monitoring appropriate because the program objective is to ensure the qualified life of devices established is not exceeded.

Detection of Aging Effects: 10 CFR 50.49 does not require the detection of aging effects for in-service components. Monitoring of aging effects may be used as a means to modify component aging limits. The staff considers the applicant's program to use monitor of aging effects as a means to modify component aging limits acceptable.

Monitoring and Trending: 10 CFR 50.49 does not require monitoring and trending of component condition or performance parameters of in-service components to manage the effects of aging. EQ program actions that could be viewed as monitoring include monitoring how long qualified component have been installed. Monitoring or inspection of certain environmental, condition or component parameters may be used to ensure that a component is within its qualification or a means to modify the qualification. The staff considers this is acceptable since 10 CFR 50.49 does not require monitoring and trending of component condition or performance parameters of in-service components to manage the effects of aging.

Acceptance Criteria: 10 CFR 50.49 acceptance criteria is that an in-service EQ component is maintained within its qualification including (a) its established aging limits and (b) continued qualification for the projected accident conditions. 10 CFR 50.49 requires refurbishment, replacement, or requalification prior to exceeding the aging limits of each installed device. When monitoring is used to modify a component aging limit, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods. The staff considers this is acceptable since it is consistent with 10 CFR 50.49 requirements of refurbishment, replacement, or requalification prior to exceeding the qualified life of each installed device.

Corrective Actions, Confirmation Process, and Administrative Controls: If an EQ component is found to be outside its qualification, corrective actions are implemented in accordance with the PBAPS corrective action process. When unexpected adverse conditions are identified during operational or maintenance activities that effect the environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. When emerging industry aging issues are identified that affect the qualification of an EQ component, the affected component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. Confirmatory actions, as needed, are implemented as part of the PBAPS corrective actions. The PBAPS EQ program is subject to administrative controls, which require formal reviews and approvals. The PBAPS EQ program will continue to comply with 10 CFR 50.49 throughout the renewal period including development and maintenance of qualification documentation demonstrating a component will perform required functions during harsh accident conditions. The PBAPS EQ program documents identify the applicable environmental conditions for the component locations. The PBAPS EQ program qualification files are maintained in an auditable form for the duration of the installed life of the component. The PBAPS EQ program documentation is controlled under the quality assurance program. The staff considers this acceptable because corrective actions, confirmation process, and administrative controls are implemented in accordance with the requirement of 10 CFR 50 Appendix B, Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants, that will insure adequacy of corrective actions, confirmation process, and administrative controls.

Operating Experience: The Peach Bottom EQ program includes consideration of operating experience to modify qualification bases and conclusions. Including aging limits. Compliance with 10 CFR 50.49 provides evidence that the component will perform its intended functions during accident conditions after experiencing the detrimental effects of in-service aging. The staff finds that the applicant has adequately addressed operating experience.

The results of the environmental qualification of electrical equipment in Section 4.4. indicate that the aging effects of the EQ of electrical equipment identified in the TLAA will be managed during the extended period of operation under 10 CFR 54.21(c)(1)(iii). However, no information is provided in the submittal on the attribute of a reanalysis of an aging evaluation to extend the qualification life of electrical equipment identified in the TLAA. The important attributes of a reanalysis are the analytical methods, the data collection and reduction methods, the underlying assumptions, the acceptance criteria, and corrective actions. The staff requested the applicant to provide information on the important attributes of reanalysis of an aging evaluation of electrical equipment identified in the TLAA to extend the qualification under 10 CFR 50.49(e).

The applicant responded, in the letter dated January 2, 2002, that the reanalysis of an aging evaluation is normally performed to extend the qualification by reducing excess conservatism incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of a component is performed on a routine basis pursuant to 10 CFR 50.49(e) as part of the Peach Bottom EQ program. While a component life limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, an unrealistically low activation energy, or in the application of a component (de-energized versus energized). The reanalysis of an aging evaluation is documented according to Peach Bottom quality assurance program requirements, which requires the verification of assumptions and conclusions. As already noted, important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). These attributes are discussed below.

Analytical Methods

The Peach Bottom EQ program analytical models used in the reanalysis of an aging evaluation are the same as those previously applied during the prior evaluation. The Arrhenius methodology is an acceptable thermal model for performing a thermal aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (that is, normal radiation dose for the projected installed life plus accident radiation dose). For license renewal, one acceptable method of establishing the 60-year normal radiation dose is to multiply the 40-year normal radiation dose by 1.5 (that is, 60 years/40 years).

The result is added to the accident radiation dose to obtain the total integrated dose for the component. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods

Reducing excess conservatism in the component service conditions (for example, temperature, radiation, cycles) used in the prior aging evaluation is the chief method used for a reanalysis per the Peach Bottom EQ Program. Temperature data used in an aging evaluation is to be conservative and based on plant design temperatures or on actual plant temperature data. When used, plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors (while the motor is not running). A representative number of temperature measurements are conservatively evaluated to establish the temperature used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as (a) directly applying the plant temperature data in the evaluation, or (b) using the plant temperature data to demonstrate conservatism when using plant design temperature for an evaluation. Any changes to material activation energy values as part of a reanalysis are to be justified on a plant-specific basis. Similar methods of reducing excess conservatism in the component service conditions used in prior aging evaluations can be used for radiation and cycling aging.

Underlying Assumptions

The Peach Bottom EQ Program EQ component aging evaluations contain sufficient conservatism to account for most environmental changes occurring due to plant modification and events. When unexpected adverse conditions are identified during operational or maintenance activities that affect the normal operating environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions.

Acceptance Criteria and Corrective Actions

Under Peach Bottom EQ Program, the reanalysis of an aging evaluation could extend the qualification of the component. If the qualification can not be extended by reanalysis, the component is be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is to be performed in a timely manner (that is sufficient time is available to refurbish, replace, or requalify the component if the reanalysis is unsuccessful).

The staff finds that the above response acceptable because it now addresses the reanalysis attribute.

4.4.1.3 Conclusions

The staff has reviewed the information in LRA Section 4.4.1 "Electrical Equipment Environmental Qualification Analyse" for the Peach Bottom Units 2 and 3 and concluded that the applicant has submitted adequate information to meet the requirements of 10 CFR 54.21(c)(1) and that the applicant has adequately evaluated the time-limited aging analyses for EQ of electrical equipment consistent with 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes the applicant has provided an adequate description of its evaluation of this TLAA and the associated program for effectivley managing aging for the period of extended operation as required by 10 CFR 54.21(d).

4.4.2 GSI-168, Environmental Qualification of Low Voltage Instrumentation and Control (I&C) Cables

4.4.2.1 Summary of Technical Information in the Application

The applicant states that NRC guidance for addressing GSI-168 "Environmental Qualification of Low Voltage Instrumentation and Control (I&C) Cables," for license renewal is contained in the June 2, 1998, NRC letter to NEI. In the letter, the NRC states: "With respect to addressing GSI-168 for license renewal, until completion of an ongoing research program and staff evaluations the potential issues associated with GSI-168 and their scope have not been defined to the point that a license renewal applicant can reasonably be expected to address them at this time. Therefore, an acceptable approach described in the Statements of Consideration is to provide a technical rationale demonstrating that the current licensing basis for environmental qualification pursuant to 10 CFR 50.49 will be maintained in the period of extended operation. Although the Statements of Consideration also indicated that an applicant should provide a brief description of one or more reasonable options that would be available to adequately manage the effects of aging, the staff does not expect an applicant to provide the options at this time."

Environmental qualification evaluations of electrical equipment are identified as time-limited aging analyses for Peach Bottom. The Peach Bottom program (Section B.4.1) evaluates the qualified lifetime of equipment in the EQ program. The existing EQ program requires that equipment qualified for 40 years be reanalyzed prior to entering the period of extended operation. The EQ program requires inclusion of any changes managed by closure of GSI-168. Consistent with the above NRC guidance, no additional information is required to address GSI-168 in a license renewal application at this time.

4.4.2.2 Evaluation

GSI-168, "Environmental Qualification of Low Voltage Instrumentation and Control (I&C) Cables," was developed to address environmental qualification of electrical equipment. The staff guidance to the industry (letter dated June 2, 1998 from NRC (Grimes) to NEI (Walters) states:

- GSI-168 issues have not been identified to a point that a license renewal applicant can be reasonably expected to address these issues, specifically at this time; and

- An acceptable approach is to provide a technical rationale demonstrating that the CLB for EQ will be maintained in the period of extended operation.

For the purpose of license renewal, as discussed in the statements of consideration (SOC) (60 FR22484, May 8, 1995), there are three options for addressing issues associated with a GSI:

- If the issue is resolved before the renewal application is submitted, the applicant can incorporate the resolution in the LRA.

- An applicant can submit a technical rationale that demonstrate the CLB will be maintained until some later point in the period of extended operation, at which time one or more reasonable options would be available to adequately manage the effects of aging.
- An applicant can develop a plant-specific aging management program that incorporates the resolution of the aging issue.

For addressing issues associated with GSI-168, the applicant continues to manage the effects of aging in accordance with the CLB and considers the evaluation of the EQ TLAA to be technical rationale that demonstrate that the CLB will be maintained during the period of extended operation. The staff finds that the applicant has addressed the issues associated with GSI-168.

4.4.2.3 Conclusions

The staff concludes that the applicant has adequately addressed the issues associated with GSI-168. The applicant will continue to manage the effects of aging in accordance with the CLB and considers the evaluation of the EQ TLAA to be the technical rationale that demonstrates that the CLB will be maintained during the period of extended operation in accordance with 10 CFR 54.21(c)(1). The staff has also reviewed the UFSAR Supplement and the staff concludes the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.5 Reactor Vessel Internals Fatigue and Embrittlement

4.5.1 Summary of Technical Information in the Application

Core Shroud and Top Guide

BWRVIP-26 [Ref.: EPRI topical report TR-107285, "BWR Vessel and Internals Project: BWR Top Guide Inspection and Flaw Evaluation Guidelines," December 1996] lists 5×10^{20} n/cm^2 as the threshold fluence beyond which the components will be significantly affected. The expected 60-year fluence on the shroud, 2.7×10^{20} n/cm^2 x 60/40 = 4.5×10^{20} n/cm^2, is below the 5×10^{20} n/cm^2 damage threshold. License Renewal Appendix C to BWRVIP-26 states that the generic fluence for 60 years on the top guide is 6×10^{20} n/cm^2. The application indicates that although this 60-year fluence will be above the 5×10^{20} n/cm^2 damage threshold, the tensile stresses in this component are very low. At these low stresses fracture is not a concern, and embrittlement is, therefore, not a threat to the intended function. These critical locations in the top guide are exempt from inspection under the approved BWRVIP-26 and no aging management activity is required.

Effect of Fatigue and Embrittlement on End-of-Life Reflood Thermal Shock Analysis

Radiation embrittlement and fatigue usage may affect the ability of certain internals, particularly the core shroud support plate, to withstand an end-of-life reflood thermal shock following a recirculation line break. Thermal shock analyses assume end-of-life fatigue and embrittlement effects and are considered TLAAs.

The applicant evaluated the effects of embrittlement and fatigue on the end-of-life reflood thermal shock analyses. The thermal shock analyses were validated for the 60- year extended operating term. The effects of embrittlement are not significant at higher usage factor locations, and the effects of fatigue are not significant at locations where embrittlement is significant. The net effect in each analyzed location is acceptable. The applicant stated that the thermal shock analyses are, therefore, acceptable for the extended operating period.

4.5.2 Staff Evaluation

Core Shroud and Top Guide

The BWRVIP inspection program for the core shroud and top guide is discussed in topical report EPRI TR-107285, "BWR Vessel and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines (BWRVIP-26)," December 1996. This report was approved by the staff in a letter from C.I. Grimes (NRC) to C. Terry (BWRVIP) dated December 7, 2000. In its safety evaluation of this report, the staff concluded that due to susceptibility to irradiation-assisted stress corrosion cracking (IASCC), applicants referencing the BWRVIP-26 report for license renewal should identify and evaluate the projected accumulated neutron fluence as a potential TLAA issue.

BWRVIP-26 lists 5×10^{20} n/cm^2 as the threshold fluence beyond which components will be susceptible to IASCC. Since the expected 60-year fluence on the shroud, is below the 5×10^{20} n/cm^2 damage threshold, the core shroud should not be susceptible to IASCC.

The staff in a telephone call on June 17, 2002, with the applicant discussed the impact of neutron radiation on the integrity of top guide components. BWRVIP-26 states that the generic fluence on the top guide for 60 years is 6×10^{20} n/cm^2, which exceeds the 5×10^{20} n/cm^2 damage threshold. The applicant stated that the location on the top guide that will see this high fluence is the grid beam. This is location 1, as identified in BWRVIP-26, Table 3-2, "Matrix of Inspection Options." In its evaluation of the top guide assembly, including the grid beam, General Electric (GE) assumed a lower allowable stress value, acknowledging the high fluence value at this location. The conclusion of this analysis, and the fact that a single failure at this location has no safety consequence, was that no inspection was considered necessary.

The staff is concerned that multiple failures of top guide beams are possible when the threshold fluence for IASCC is exceeded. According to BWRVIP-26, multiple cracks have been observed in top guide beams at Oyster Creek. In addition, baffle-former bolts on PWRs that exceeded the threshold fluence have had multiple failures. In order to exclude the top guide beam from inspection when its fluence exceeds the threshold value, the applicant must demonstrate that failures of multiple beams (all beams that exceed the threshold fluence) will not impact the safe shutdown of the reactor during normal, upset, emergency, and faulted conditions. If this can not be demonstrated, the applicant should propose an aging management program (AMP) for these components which contain the elements in Branch Technical Position RLSB-1 of NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," July 2001. This was Open Item 4.5.2-1.

In Attachment 3 to a letter from M. P. Gallagher to USNRC dated January 14, 2003, the applicant provided a revised Reactor Pressure Vessel and Internals ISI Program (B.2.7) which indicates Peach Bottom will perform augmented inspections for the top guide similar to the inspections of Control Rod Drive Housing (CRDH) guide tubes. The sample size and frequency for CRDH guide tubes is a 10% sample of the total population within 12 years; one half (5%) to be completed within six years. The method of examination is an enhanced visual examination (EVT-1). EVT-1 are utilized to examine for cracks. The program will be implemented prior to the end of the initial operating license term for Peach Bottom. The applicant also stated that it might modify the above agreed-upon inspection program should the BWRVIP-26, "BWR Vessels and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines (BWRVIP-26)," be revised in the future. This is acceptable to the staff because any modifications to the BWRVIP-26 program through the BWRVIP are reviewed and approved by the staff. Since the aging effect is IASCC, the staff requested the applicant to clarify whether the inspection sample would be in top guide locations that receive the greatest amounts of neutron fluence. In a letter from M. P. Gallagher to USNRC dated January 29, 2003, the applicant concluded that future locations for the top guide inspections will be in the center or close to the center of the core in the high fluence region. The conclusion is based on the applicant's experiences with prior CRDH inspections. Since the applicant has proposed an inspection program which will be able to detect IASCC in locations which receive high neutron fluence, the staff considers the program acceptable; therefore, Open Item 4.5.2-1 is closed.

Effect of Fatigue and Embrittlement on End-of-Life Reflood Thermal Shock Analysis

Radiation embrittlement and fatigue usage may affect the ability of certain reactor vessel internals (RVI), particularly the core shroud support plate, to withstand an end-of-life reflood thermal shock following a recirculation line break. The applicant evaluated the effects of embrittlement and fatigue on the end-of-life reflood thermal shock analysis. The thermal shock analyses were validated for the 60-year extended operating term. The effects of embrittlement are not significant at higher usage factor locations, and the effects of fatigue are not significant at locations where embrittlement is significant. Based on the applicant's evaluation of the impact of fatigue and embrittlement on RVI components, the staff concludes that reflood thermal shock will not significantly affect the capability of RVI components to perform their intended functions during the 60-year extended operating term. The impact of reflood thermal shock on the reactor vessel is discussed in Section 4.2.1 of this SER.

4.5.3 Conclusions

The staff concludes that the reactor vessel internals embrittlement analyses have been evaluated and remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Because of the above open item the staff cannot conclude that the UFSAR Supplement provides an adequate description of the evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d). Pending resolution of the open item, the staff will determine if the UFSAR Supplement contains an appropriate summary description.

The effect of fatigue and embrittlement on end-of-life reflood thermal shock analysis have been evaluated and remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). The staff has also reviewed the UFSAR Supplement and the staff concludes the applicant has provided an adequate description of its evaluation of this TLAA for the period of extended operation as required by 10 CFR 54.21(d).

4.6 Containment Fatigue

The applicant stated that, subsequent to the original design, elements of Peach Bottom containments were reanalyzed for fatigue due to unevaluated pressure and temperature cycles discovered by GE and others, resulting from design basis events, including loss of coolant accidents, safety relief valve discharge, and combinations of loads resulting from these conditions. The re-evaluation consisted of (1) generic analyses applicable to each of several classes of BWR containments and (2) plant-unique analyses (PUA) from the Mark 1 Containment Program. The scope of these analyses included the tori, the drywell-to-torus vents, SRV discharge piping, other torus-attached piping and its penetrations, and the torus vent bellows.

Since there are no hydrodynamic loads acting on the containment, fatigue is not considered in containment design except at penetrations or other stress concentration areas. The drywell shell plate was not evaluated for fatigue in the original design; the PUA also did not reevaluate the drywell, the drywell penetrations, or the process piping penetration bellows which are attached to the piping. No fatigue analyses were identified in the licensing and design basis documents for Peach Bottom for these components. However, the drywell process bellows were originally specified for a finite number of operating cycles, and the design of these bellows is therefore identified as a TLAA.

4.6.1 Fatigue Analysis of Containment Pressure Boundaries: Analysis of Tori, Torus Vents, and Torus Penetrations

4.6.1.1 Summary of Technical Information in the Application

The applicant stated that the tori were originally evaluated for a maximum of 800 SRV events. For the stress cycles associated with SRV and other dynamic events, the PUA calculated maximum design life CUFs in excess of 0.666 for locations on the torus and drywell-to-torus vents. The CUFs for these locations will therefore exceed the ASME Section III Code allowable of 1.0 for the period of extended operation. For most torus, vent, and torus penetration locations the predicted CUF is less than 0.666. However, this CUF value does not provide analytical or event margin. The applicant has therefore chosen a calculated CUF of 0.4 or less as the validation limit for 60 years of operation. Locations whose 40-year CUF exceeds 0.4 will be included in the Fatigue Management Program (FMP), described in Section B.4.2 of the Application.

The FMP counts fatigue stress cycles, tracks fatigue usage factors, and calculates CUFs from modeling equations. For the torus, vent, and torus penetration the CUF model is made up of contributions resulting from normal operation and design basis worst case LOCA cyclic transients. The applicant stated that during normal operation, only SRV load cases contribute to fatigue. As part of the FMP, the fatigue analyses will be revised to show that the SRV contribution will not exceed the Code CUF limit during the period of extended operation. This will be confirmed for the duration of the extended operating period by monitoring fatigue at the high-usage-factor locations in the tori, torus vents and penetrations with the FMP, and tracking the CUFs at these locations using the CUF modeling equations, based on the monitored plant transients. These equations will be updated as necessary, and transient events will be tracked to ensure that the CUF due to normal operating transients will remain less than 1.0. The FMP also permits fatigue reanalysis of the high-usage-factor locations. Conservatism in the original containment PUA may permit the reduction of the total calculated CUFs below the limiting value of 0.4, for which fatigue monitoring would be required. Most locations have been evaluated and remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Those that do not remain valid will require management of the aging effects, in accordance with 10 CFR 54.21(c)(1)(iii).

4.6.1.2 Staff Evaluation

The applicant has performed fatigue analyses of the tori, torus vents and torus penetrations that include new Peach Bottom loads. A limit of CUF =0.4 for 40 years as an acceptance criterion was selected to determine if the analyses will remain valid for the period of extended operation. Those locations with CUF<0.4 will remain valid, pursuant to 10 CFR 54.21(c)(1)(i). For those locations that exceed the threshold, the effects of fatigue will be managed during the period of extended operation by the FMP cycle counting and fatigue CUF tracking program, pursuant to 10 CFR 54.21(c)(1)(iii).

4.6.1.3 Conclusions

Pursuant to 10 CFR 54.21(c), the staff finds the proposed acceptance limit CUF of 0.4 acceptable. The staff also finds the use of the FMP, to ensure that fatigue effects will be adequately managed and will be maintained within Code design limits for the period of extended operation, reasonable and acceptable. The applicant has also provided an adequate summary of the information related to the fatigue analysis of the tori, torus vents and penetrations in Section A.5.4.1 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.6.2 Fatigue Analysis of SRV Discharge Lines and External Torus-Attached Piping

4.6.2.1 Summary of Technical Information in the Application

The SRV discharge lines and external torus-attached piping were analyzed separately from the tori and the torus vents. The analysis included the SRV lines and all piping and branch lines, including small-bore piping attached to the tori, pipe supports, valves, flanges, equipment nozzles and equipment anchors. The applicant stated that the highest fatigue CUF, calculated in the PUA on the basis of 800 SRV actuations was 0.202. The applicant concludes that the fatigue analyses of this piping will remain valid for the period of extended operation.

4.6.2.2 Staff Evaluation

The applicant has described a conservative approach to determining the fatigue evaluation of the SRV discharge lines and external torus-attached piping. The staff finds this approach reasonable and acceptable.

4.6.2.3 Conclusions

Pursuant to 10 CFR 54.21(c)(1)(i), the staff finds that the applicant's evaluation of the fatigue analyses of the SRV discharge lines and external torus-attached piping demonstrate that these TLAAs will remain valid for the period of extended operation. The applicant has also provided an adequate summary of the information related to the fatigue analysis of the SRV discharge lines and external torus-attached piping in Section A.5.4.2 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.6.3 Expansion Joints and Bellows Fatigue Analyses: Drywell-to-Torus Vent Bellows

4.6.3.1 Summary of Technical Information in the Application

The applicant has stated that the PUA-calculated fatigue usage factors for the drywell to torus vent bellows are negligible.

4.6.3.2 Staff Evaluation

The staff considers the results of the PUA for these components reasonable and acceptable.

4.6.3.3 Conclusions

Pursuant to 10 CFR 54.21(c)(1)(i), the staff finds that the applicant's evaluation of the fatigue analysis of the drywell-to-torus vent bellows demonstrates that these TLAAs will remain valid for the period of extended operation. The applicant has also provided an adequate summary of the information related to the fatigue analysis of the drywell-to-torus vent bellows in Section A.5.4.3 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.6.4 Expansion Joint and Bellows Fatigue Analyses: Containment Process Penetration Bellows

Expansion Joint and Bellows Fatigue Analyses: Containment Process Penetration Bellows has been identified as a TLAA for the purposes of license renewal. The staff reviewed LRA Section 4.6.4 to determine whether the applicant submitted adequate information to meet the requirements of 10 CFR 54.21(c).

4.6.4.1 Summary of Technical Information in the Application

The applicant stated that at Peach Bottom, the only containment process piping expansion joints and bellows subjected to significant thermal expansion and contraction cycling are those between the drywell shell penetrations and process piping. The design of containment boundary components for a stated number of cycles over the design life constitutes a TLAA, in accordance with 10 CFR 54.3. Some process expansion joints have been replaced with components designed to later code and specification requirements. These bellows were designed to the requirements of ASME Code Section III and specified a minimum of 200 "startup-and-shutdown" cycles and a minimum of 1,500 "normal operating" cycles. Both the original and replaced components were designed for a number of equivalent full-temperature thermal cycles in excess of their specifications. The bellows were initially designed and supplied for operation in excess of 10,000 operating and thermal cycles. The replacement bellows were designed for operation in excess of 50,000 cycles. The PUA did not include any reanalysis of the expansion joints.

4.6.4.2 Staff Evaluation

Based on the applicant's description, the design cycles of the original and replacement bellows exceed the requirements of the original specifications and the estimate of the thermal cycles that might be expected to occur during the period of extended operation. The fatigue analyses of the penetrations therefore demonstrate ample margin for continuing operation during the period of extended operation.

4.6.4.3 Conclusions

Pursuant to 10 CFR 54.21(c)(1)(i), the staff finds that the applicant's evaluation of the fatigue analysis of the expansion joint and bellows demonstrates that these TLAAs will remain valid for the period of extended operation. The applicant has also provided an adequate summary of the information related to the fatigue analysis of the containment process penetration bellows in Section A.5.4.4 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.7 Other Plant-Specific TLAAs

4.7.1 Reactor Vessel Main Steam Nozzle Cladding Removal Corrosion Allowance

4.7.1.1 Summary of Technical Information in the Application

The original reactor vessel corrosion allowances were conservative values intended to encompass 40 years of operation without reliance on a particular corrosion rate. However, a subsequent calculation to justify removal of the main steam nozzle cladding used a time-dependent corrosion rate for 40 years and is therefore a TLAA.

The applicant evaluated corrosion data for unclad portions of the vessel interior were evaluated and predicted a loss of about 0.030 inches in 60 years. The main steam nozzle clad removal calculation was validated to confirm that the 1/16 inch (.065 inch) corrosion allowance is conservative for 60 years of operation.

4.7.1.2 Staff Evaluation

In response to RAI 4.7-1, the applicant identified the basis for the corrosion rate and the sources for the data. Based on the average of the available data, corrosion rates were determined for high- and low-temperature operating conditions. Assuming 54 years at high temperature and 6 years at low temperature (90% availability for 60 years of operation), and doubling the average corrosion rate, the amount of corrosion for 60 years of operation was estimated to be 0.030 inch. The analysis is acceptable to the staff because the analysis used the average of all available data and conservatively doubled the average corrosion rate to estimate the amount of corrosion for 60 years of operation. Based on the applicant's conservative analysis of the predicted loss of material resulting from corrosion during 60 years of operation, the staff concludes that the corrosion allowance identified when the clad was removed from the main steam nozzles is valid for 60 years of operation.

4.7.1.3 Conclusions

The reactor vessel main steam nozzle clad removal corrosion allowances have been evaluated and remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). The applicant has also provided an adequate summary of the information related to the above analysis in Section A.5.5.1 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.7.2 Generic Letter 81-11 "Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking"

4.7.2.1 Summary of Technical Information in the Application

The applicant describes its evaluation of the feedwater nozzle and control rod drive return line nozzle cracking TLAA in LRA Section 4.7.2, "Generic Letter 81-11 Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, *BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking*," and in Section A.5.6, "Inservice Flaw Growth Analyses that Demonstrate Structural Integrity for 40 Years," of Appendix A, "Updated Final Safety Analysis Report (UFSAR) Supplement," of the LRA. The applicant proposes to manage crack growth associated with the TLAA by an NRC-approved BWR Owners Group (BWROG) inspection program.

By late 1970s, inservice inspections (ISIs) discovered cracking on the inside surface of feedwater and control rod drive return line (CRDRL) nozzles at several BWR plants in the United States. The cracking was attributed to thermal cycling due to turbulent mixing of relatively cooler CRDRL water and leaking feedwater with hot downcomer flow. The CRDRL nozzles have been capped at Peach Bottom Units 2 and 3 to eliminate cracking due to thermal cycling.

The applicant has taken the following three actions as recommended by NUREG-0619 and Generic Letter 81-11 to reduce or eliminate the causes of cracking of feedwater nozzles: (a) installation of improved triple thermal sleeves with dual piston ring seals, (b) removal of cladding from the nozzle bore and blend radii, and (c) improvement of the low-flow controller. The applicant now uses the NRC-approved improved BWROG inspection and management methods in lieu of NUREG-0619 methods. The BWROG methods depend on a fracture mechanics analysis and ultrasonic inspection from the vessel and nozzle exterior. The fracture mechanics analysis is used to determine the inspection interval. This analysis is not a TLAA because it does not involve time-limited assumptions defined by the current operating term.

The nozzle crack growth, however, must be acceptable for the period of extended operation to ensure the continued validity of the assumptions of fatigue analyses for the reactor pressure vessel, which are TLAAs.

The feedwater nozzle is subject to the combined effect of long-term, low-cycle thermal fatigue due to heatup, cooldown, and other operational transients (which affects the entire vessel, including the nozzle wall) and high-cycle thermal fatigue due to leaking feedwater (which only affects inner surface of the feedwater nozzle). The UFSAR description of this issue includes an evaluation of this combined effect, which is a TLAA. However, these two fatigue effects are separable. Table 3.1-1 of the LRA includes both cumulative fatigue damage and cracking as aging effects due to fatigue for BWR feedwater nozzle. The applicant proposes the use of NRC-approved BWROG inspection methods, which no longer depend on this combined fatigue evaluation, to manage cracking due to rapid thermal cycling, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

4.7.2.2 Staff Evaluation

The relatively cooler water leaking past the loosely fitted thermal sleeves installed inside the feedwater nozzles has caused cracking of these nozzles in a large number of BWR plants in the United States during 1970s. The cracks were discovered on the inside surface of the nozzles at the blend radius and bore. The leaking water (also called bypass leakage) turbulently mixed with hot downcomer flow in the annulus between the nozzle and thermal sleeve and put high-cycle fatigue loads on the nozzle inside wall. The cracks initiated by the high-cycle fatigue are arrested at a shallow depth (~6 mm) because the thermal stresses induced by the high-cycle fatigue have steep gradients and shallow depth. These cracks are further propagated by low-cycle fatigue due to plant heatup, cooldown, and feedwater on-off transients. These transients produce large, throughwall, stress cycles on the nozzle wall and in time could drive the cracks to significant depth. Such cracking has been discovered in the feedwater nozzles at Peach Bottom Units 2 and 3.

Similarly, the relatively cooler water passing through the CRDRL nozzle turbulently mixes with hot downcomer flow and causes cracking on the inside surface of the nozzle and also on the wall of the reactor pressure vessel beneath the nozzle. Such cracking has been discovered at the CRDRL nozzles at Peach Bottom Units 2 and 3. The applicant reports that these nozzles were capped after the cracks were repaired and are no longer susceptible to damage due to rapid thermal cycles. Therefore, the staff concludes that cracking of the CRDRL nozzles no longer requires aging management for license renewal at Peach Bottom Units 2 and 3.

NUREG-0619 recommended that the licensees take the following six actions to reduce the potential for initiation and growth of cracks in the inner nozzle areas: (1) remove the cladding from the inner radii; (2) replace loose-fitting or interference-fitting sparger thermal sleeves; (3) evaluate the acceptability of the flow controller; (4) modify operating procedures to reduce thermal fluctuations; (5) reroute reactor water cleanup system (RWCU) discharge to both feedwater loops; and (6) conform to the inspection interval specified in Table 2 of NUREG-0619. In 1981, the NRC staff issued Generic Letter 81-11 to amend the recommendations in NUREG-0619, thereby allowing plant-specific fracture mechanics analysis in lieu of hardware modifications.

The first three of the NUREG-0619 recommendations have been implemented at Peach Bottom Units 2 and 3: cladding has been removed from the nozzle bores and blend radii, improved triple thermal sleeves with dual piston ring seals have been installed, and the low-flow controllers have been improved. The implementation of these recommendations has been effective in preventing cracking of the feedwater nozzle. An industry report, GE-NE-523-A71-0594-A, Revision 1, "Alternate BWR Feedwater Nozzle Inspection Requirements," May 2000, states that no new cracking has been identified in the BWR feedwater nozzles since 1984.

The feedwater nozzle is susceptible to the combined effect of low-cycle thermal and mechanical fatigue due to heatup, cooldown, and feedwater on-off transients and high-cycle thermal fatigue due to bypass leakage. The evaluation of this combined effect is a TLAA. The applicant, however, states that these two fatigue effects are separable and proposes two different aging management programs to manage them. The aging effect of low-cycle fatigue is cumulative fatigue damage, whereas the aging effects of high-cycle thermal fatigue is cracking. Several of the NUREG-0619 recommendations implemented at Peach Bottom Units 2 and 3 have reduced the potential for racks due to rapid thermal cycling damage. Consequently, the susceptibility to crack initiation at the feedwater nozzle blend radius and bore has also been reduced. This reduced susceptibility to cracking is supported by the significant field experience with the successful prevention of cracks in feedwater nozzles since implementation of the NUREG-0619 recommendations, as mentioned earlier. So the remaining aging effect of high-cycle fatigue is the growth of an existing crack that was initiated earlier by rapid thermal cycling caused by bypass leakage. Therefore, the staff conclude that the separation of two fatigue effects, cumulative fatigue damage and crack growth, is justified.

NUREG-0619 identified the inservice inspection requirements based on the state-of-the-art in the late 1970s. The required inservice inspection included both ultrasonic testing (UT) of the entire nozzle and dye-penetrant testing (PT) of various portions of blend radius and bore. Since the issuance of NUREG-0619, significant advances have been made in UT inspection technology, and significant field experience has been gained on the successful prevention of cracks in feedwater nozzles. As a result of these improvements, BWROG proposed that UT inspections replace the PT inspections specified in NUREG-0619, and that UT inspection intervals be based on sparger-sleeve configurations and specific UT inspection methods as described in the report GE-NE-523-A71-0594-A, Revision 1. This report specifies UT of specific regions of the nozzle inner blend radius and bore. The nozzle inner blend radius region is more limiting from a fracture mechanics point of view than the bore region. The UT examination techniques and personnel qualifications are in accordance with the guidelines of GE-NE-523-A71-0594-A, Revision 1. The examination techniques include manual, automatic and phased-array UT methodologies. In a letter from SA. Richards to W. Glenn Warren, dated March 10, 2000, "Final Safety Evaluation of BWR Owners Group Alternative BWR Feedwater Nozzle Inspections," the NRC staff accepted the proposed BWROG inspection methods and fracture mechanics analysis. These NRC-approved BWROG inspection methods and inspection intervals are currently being used at Peach Bottom. The applicant proposes to continue the use of these inspection methods during the extended period of operation.

The BWROG inspection methods require fracture mechanics analysis to estimate the time required for an assumed crack (an initial crack depth of ~6 mm [0.5 inch]) to reach the generic allowable value (1 inch) or to reach an allowable value based on plant-specific analysis. Plant-specific analysis must follow the recommendations of Section 5.6 of the report GE-NE-523-A71-0594-A, Revision 1. The BWROG method determines the inspection interval as a fraction of the time taken for this crack growth. The magnitude of the fraction and therefore the size of the inspection interval depend on the thermal sleeve-sparger design configuration, the UT inspection technique employed, and the specific region of the nozzle inspected. The maximum allowable inspection interval for the nozzle inner blend radius is 10 years. This fracture mechanics analysis is not a TLAA because it is used to determine the inspection interval and not to determine whether the crack growth at the end of the current 40-year licensed operating period is acceptable, and so does not involve time-limited assumptions for the current operating term. The GE generic fracture mechanics evaluation show that there is significant margin available to the allowable depth of 1 inch. The report recommends that the fatigue crack growth curves from Section XI of the ASME Code be utilized in the fracture mechanics analysis. To predict crack growth, Peach Bottom performed the fracture mechanics analysis of feedwater nozzle subjected to thermal cycles expected during the extended period of operation. Analysis at Peach Bottom predicts that growth from the assumed initial flaw size to the allowable value will take about 60 years.

The NRC-approved BWROG inspection methods, along with acceptance criteria and corrective actions are included in the aging management program presented in LRA Section B.2.7, "RPV and Internals ISI Program." The evaluation of this program is presented in Section 3.0.3.9 of this

SER. In addition to these inspections, the applicant proposes to do a periodic review of the fracture mechanics analysis, in conjunction with the fatigue management program presented in Section B.4.2 of the LRA, to ensure that the fracture mechanics evaluation remains bounding and applicable for its intended purpose. The staff finds the applicant's commitments acceptable.

4.7.2.3 Conclusions

The staff has reviewed the information presented in LRA Section 4.7.2, "Generic Letter 81-11 Crack Growth Analysis to Demonstrate Conformance to the Intent of NUREG-0619, *BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking*." On the basis of this review, the staff concludes that the applicant has adequately evaluated this TLAA, as required by 10 CFR 54.21(c)(1). Specifically, the staff concludes that the RPV and Internals ISI program will ensure that any cracking in the feedwater nozzle will be adequately detected and managed, within the limits of the supporting fracture mechanics analyses, for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(iii). The applicant has also provided an adequate summary of the information related to the above analysis in Section A.5.6.1 of the UFSAR Supplement as required by 10 CFR 54.21(d).

4.7.3 Fracture Mechanics of ISI-Reportable Indications for Group 1 Piping: As-forged Laminar Tear in a Unit 3 Main Steam Elbow Near Weld 1-B-3BC-LDO Discovered During Preservice UT

4.7.3.1 Summary of Technical Information in the Application

The applicant reported that a preservice UT volumetric examination discovered an imbedded as-forged laminar tear in the Unit 3 main steam elbow material. The UT indication did not extend to the weld.

To determine the effect of the flaw on the life of the steam line, the applicant performed an ASME Section III Class 1 fatigue analysis of the main steam elbow with the flaw, considering 40 years of operation. The analysis determined that the primary, secondary, and primary plus secondary stresses are within the Code allowable limits, and calculated a 40-year cumulative usage factor (CUF) of 0.012. The applicant stated that if the laminar tear extended to the weld joint, the CUF would rise to 0.036, and would not exceed to 0.054 for the period of extended operation. These values are below the Code design limit of 1.0.

4.7.3.2 Staff Evaluation

Ordinarily, fatigue analyses of steam lines in accordance with ASME Section III Class 1 are not required, since these are not Class 1 components. However, for the elbow with flaws, the applicant chose to perform an ASME Section III Class 1 fatigue analysis and demonstrate that the calculated CUF is below the Code design limit of 1.0 for 40-year operation and also for the period of extended operation. A CUF of 1.0 is considered the approximate threshold at which a fatigue crack may initiate and propagate. The staff's interpretation is that the applicant's intent was to consider the discovered flaw as a local discontinuity in the elbow geometry. The effect of the flaw is accounted for by the introduction of a fatigue strength reduction factor, or an equivalently stress concentration factor, as specified in the ASME Section III Subsection NB design rules. By reporting that the CUF is considerably below the design limit of 1.0, the staff concludes that the applicant has provided reasonable assurance that the flaw will not propagate during operation during the 40-year life of the plant and the period of extended operation.

4.7.3.3 Conclusions

Pursuant to 10 CFR 54.21(c)(1)(i), the staff finds that the applicant's evaluation of the effect of a laminar tear discovered during a preservice ultrasonic examination on the structural integrity of the steam line elbow by an ASME Section III Class 1 fatigue analyses is acceptable, and that the applicant has demonstrated that this TLAA will remain valid for the period of extended operation. The applicant has also provided an adequate summary of the information related to the fatigue evaluation of a laminar tear discovered during a preservice inspection in a steam line elbow in Section A.5.6.2 of the UFSAR Supplement as required by 10 CFR 54.21(d).

5 REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

On September 13, 2002, the staff issued its safety evaluation report (SER) with open and confirmatory items related to the license renewal of Peach Bottom Atomic power station, Units 2 and 3. On October 30, 2002, the Advisory Committee on Reactor Safeguards (ACRS) conducted a review of the 10 CFR Part 54 portion of the Peach Bottom license renewal application and the SER with open items. The staff finalized and issued its SER related to the license renewal of the Peach Bottom Atomic Power Station, Units 2 and 3, on February 5, 2003.

During its 500th meeting on March 6, 2003, the ACRS full committee completed its review of the Peach Bottom license renewal application and the NRC staff's SER. The ACRS documented its findings in a letter to the Commission dated March 14, 2003. A copy of the ACRS full committee report is attached.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D.C. 20555-0001

March 14, 2003

The Honorable Richard A. Meserve
Chairman
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE PEACH BOTTOM ATOMIC POWER STATION UNITS 2 AND 3

Dear Chairman Meserve:

During the 500th meeting of the Advisory Committee on Reactor Safeguards, March 6-8, 2003, we completed our review of the license renewal application for the Peach Bottom Atomic Power Station Units 2 and 3 and the final Safety Evaluation Report (SER) prepared by the NRC staff. Our Plant License Renewal Subcommittee also reviewed this matter during a meeting on October 30, 2002. During our review, we had the benefit of discussions with representatives of the NRC staff and Exelon Generation Company, LLC (Exelon). We also had the benefit of the documents referenced.

RECOMMENDATIONS AND CONCLUSIONS

1. The Exelon application for renewal of the operating licenses for Peach Bottom Atomic Power Station Units 2 and 3 should be approved.

2. The programs instituted by the applicant to manage age-related degradation are appropriate and provide reasonable assurance that Peach Bottom Atomic Power Station Units 2 and 3 can be operated in accordance with their current licensing bases for the period of extended life without undue risk to the health and safety of the public.

3. The scram at Peach Bottom Unit 2 that occurred on December 21, 2002, highlighted a number of weaknesses in the current corrective action and preventive maintenance programs. We expect that ongoing corrective actions committed by the licensee will resolve these weaknesses.

BACKGROUND AND DISCUSSION

This report fulfills the requirement of 10 CFR 54.25 which states that the ACRS review and report on license renewal applications. Peach Bottom Units 2 and 3 are General Electric boiling water reactors (BWRs) Type 4, with Mark I containments. Exelon requested renewal of their operating licenses for 20 years beyond the current license terms, which expire on August 8, 2013 for Unit 2 and July 2, 2014 for Unit 3. Peach Bottom Unit 1 is on the same site as Units 2 and 3. It is permanently shutdown and in SAFSTOR condition. There are no systems shared between Unit 1 and Units 2 and 3.

The final SER documents the staff's review of the information submitted by Exelon, including commitments that were necessary to resolve open items identified by the staff in the initial SER. Peach Bottom is the second BWR plant to seek license renewal and the first to use a system-based approach to identify structures, systems, and components (SSCs) that should be included in the scope of license renewal. The staff reviewed the completeness of the applicant's identification of SSCs that are subject to aging management; the integrated plant assessment process; the identification of the possible aging mechanisms associated with passive, long-lived components; and the adequacy of the aging management programs. The staff also conducted several inspections at Exelon's engineering offices and the Peach Bottom site to verify the adequacy of the methodology described in the application and its implementation.

During our Plant License Renewal Subcommittee meeting on October 30, 2002, the staff presented a well-structured and effective overview of its inspections. As in other applications, the review of the Peach Bottom license renewal application required a substantial number of requests for additional information (RAIs) and depended heavily on review of plant drawings at the site.

On the basis of our review of the final SER, we agree with the staff's conclusion that all open items and confirmatory items have been appropriately closed, and there are no issues that would preclude renewal of the operating licenses for Peach Bottom Units 2 and 3. We also concur with all four license conditions requiring the applicant to take certain actions before beginning the period of extended operation.

The process implemented by the applicant to identify SCCs that are within the scope of license renewal has been effective. The applicant included portions of nonsafety-related systems in the scope of license renewal if their failure could impact in-scope safety-related systems. When a system met this criterion, the entire system, passing through seismic Class I structures, was considered in scope. Portions of these systems that run through non-seismic structures were evaluated by walkdowns and were added to the scope as appropriate. An example of such a system is the service water system that could spray liquid on the safety systems.

Certain nonsafety systems have portions that perform a safety function, and the applicant realigned these portions to be included as part of the in-scope safety system. For example, a nonsafety-related system such as chilled water or instrument air that penetrates the containment has been realigned to be considered in scope as a part of the containment pressure retaining function. The in-scope portions of the realigned system typically include the first valve outside and inside containment and all of the piping in between.

Peach Bottom is located on the Susquehanna River on a large pond created by the Conowingo Dam (also owned by Exelon). Peach Bottom relies on the pond for operation of the units, but does not depend on the pond for emergency service water. It does depend, however, on power from Conowingo for station blackout (SBO) via a submerged electrical cable. Consequently, Conowingo is in scope for SBO considerations. The license for the Conowingo Dam will expire before the extended license period for the Peach Bottom Plant and is expected to be renewed. Should this not occur, other provisions for SBO will be required.

Open items have been closed by bringing all identified SSCs into scope. During our review, we questioned why certain other SSCs were not included in scope and, in all cases, the applicant provided appropriate justification for their exclusion. We conclude that the applicant and the staff have appropriately identified all SSCs that are within the scope of license renewal.

The applicant also performed a comprehensive aging management review of all SSCs that are within the scope of license renewal. The application describes 34 aging management programs for license renewal, which include existing, augmented, and new programs.

The applicant has proposed to inspect only the refueling water storage tank and infer from that inspection the condition of the condensate storage tank. Since these storage tanks are similar in construction, are exposed to similar water chemistry, and are located in similar environments, we agree with the staff that this is an acceptable approach.

Peach Bottom Units 2 and 3 have toroidal suppression pools and there was discussion regarding the material condition of the coating and steel. The applicant satisfactorily described inspections conducted to date to ensure the quality of material condition of the coating and steel and also described plans for future inspections.

There was a concern that the applicant did not appear to have an aging management program for the buried portions of the standby gas treatment system (SGTS) ductwork. The applicant stated that the ductwork was either hot and/or insulated and no aging management program was required. During the third license renewal inspection at Peach Bottom, the inspectors visually examined accessible exterior and interior surfaces of the SGTS and found no age-related degradation. Based on the results of this inspection, the staff agreed with the applicant.

Peach Bottom has had a history of cable failure due to moisture intrusion in 4Kv and 13Kv service. Many cables have been replaced with moisture-resistant cables. In recent NRC inspections, water intrusion was evident in certain manholes and seems to be an ongoing problem. Consequently, the applicant committed to a program to manage the aging of inaccessible medium-voltage cables. This aging management program provides reasonable assurance that the intended functions of the systems and components will be maintained consistent with the current licensing basis during the period of extended operation.

With regard to the inspection of reactor vessel internals, the applicant has committed to the programs prescribed in 15 BWR Vessel and Internals Project (BWRVIP) reports. These programs have all been approved by the NRC staff for 60 year plant life except those described in BWRVIP-78, BWR Integrated Surveillance Program, and BWRVIP-86, BWR Integrated Surveillance Program Implementation Plan, which are approved only for 40 year plant life. The staff is currently reviewing these BWRVIP reports for 60 years. The applicant has agreed to a license condition to notify the NRC, before entering the period of extended operation, of its decision to implement either the staff-approved integrated surveillance program (ISP) or a staff-approved plant-specific ISP. Also, the staff has not yet approved BWRVIP-76, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines." Because the staff's review is not complete, the applicant has agreed to another license condition to notify the NRC of its decision to implement either the staff-approved core shroud inspection and evaluation guidelines program, or a staff-approved plant-specific program.

Exelon has also identified those components at Peach Bottom that are supported by time-limited aging analyses (TLAAs). These TLAAs show that the components analyzed have sufficient margin to operate for the period of extended life.

Peach Bottom Unit 2 experienced a scram on December 21, 2002. This event highlighted a number of weaknesses in the current corrective action and preventive maintenance programs. We expect that ongoing corrective actions committed by the licensee will resolve these weaknesses. During inspections, the staff should assess the effectiveness as well as the adequacy of implementation of these programs.

The applicant and the staff have identified plausible aging effects associated with passive, long-lived components. Adequate programs have been established to manage the effects of aging so that Peach Bottom Units 2 and 3 can be operated in accordance with their current licensing bases for the period of extended life without undue risk to the health and safety of the public.

Sincerely,

Mario V. Bonaca

Mario V. Bonaca
Chairman

References:

1. Letter dated July 2, 2001, from J. A. Benjamin, Exelon Generation Company, LLC, to U. S. Nuclear Regulatory Commission, transmitting Application to Renew the Operating Licenses of Peach Bottom Atomic Power Station Units 2 and 3
2. U.S. Nuclear Regulatory Commission, NUREG-XXX, "Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3" February, 2003.

6 CONCLUSIONS

The staff reviewed the Peach Bottom Atomic Power Station, Units 2 and 3, license renewal application in accordance with Commission regulations and the NRC "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," dated July 2001. The Commission's regulatory standards for issuance of a renewed license are in 10 CFR 54.29.

In a safety evaluation report (SER) issued on September 13, 2002, the staff identified a number of open and confirmatory items. All of those items have been resolved, as discussed in this SER. On the basis of its evaluation of the application, as discussed above, the staff concludes that: (1) actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require an aging management review under 10 CFR 54.21(a)(1), and (2) actions have been identified and have been or will be taken with respect to time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c). Accordingly, the staff finds that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis for the Peach Bottom Atomic Power Station, Units 2 and 3. The staff notes that the requirements of subpart A of 10 CFR Part 51 are documented in the final plant-specific supplement to the Generic Environmental Impact Statement issued on January 22, 2003.

APPENDIX A
CHRONOLOGY

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and Exelon Generation Company, LLC (Exelon), regarding the NRC staff's review of the Peach Bottom Atomic Power Station (PBAPS), Unit 2 and 3, license renewal application (LRA) (Docket Nos. 50-277 and 50-278).

July 2, 2001	In a letter signed by J. Benjamin, Exelon submitted its application to renew the operating licenses of Peach Bottom Atomic Power Station, Units 2 and 3. In its submittal, Exelon provided the original of the application, 17 paper copies and 30 copies of the application on CD-ROM.
July 2, 2001	In a letter signed by J. Benjamin, Exelon submitted four sets of boundary drawings to the NRC.
July 18, 2001	In a letter signed by D. Matthews, NRC informed Exelon that the NRC had received its application to renew the operating licenses of Peach Bottom Atomic Power Station, Units 2 and 3, on July 2, 2001, and that Mr. Raj Anand was appointed as the project manager for the Peach Bottom LRA.
July 25, 2001	NRC published a *Federal Register* notice (FRN) of the receipt of the Peach Bottom Atomic license renewal application.
August 27, 2001	In a letter signed by R. Anand, NRC issued a summary of the public meeting held on August 14, 2001. In this meeting, Exelon made a presentation to the NRC staff and members of the public regarding information contained in the Peach Bottom LRA.
August 31, 2001	NRC published an "acceptance for docketing and opportunity for hearing" *Federal Register* notice (FRN) regarding the Peach Bottom LRA.
September 5, 2001	In a letter signed by D. Matthews, NRC informed Exelon that the NRC staff determined that the contained information in the Peach Bottom LRA submitted on July 2, 2001, was acceptable for docketing and sufficient for the staff to begin its review.
October 26, 2001	In a letter signed by R. Anand, NRC issued the summary of a public meeting between the staff and Exelon representatives. The meeting was held on September 24 and 25, 2001, to discuss the scoping and screening methodology and electrical sections of the PBAPS LRA.
October 30, 2001	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the scoping and screening methodology discussed in Section 2.1 of the Peach Bottom LRA.

November 5, 2001	In a letter to Exelon signed by R. Anand, the NRC staff issued a summary of the public meeting held on October 22, 2001. In this meeting Exelon provided clarifications of the scoping and screening process discussed in the Peach Bottom LRA.
November 16, 2001	In a letter to Exelon signed by R. Anand, the NRC staff provided the schedule for the review of the Peach Bottom Atomic Power Station, Unit 2 and 3, LRA.
November 16, 2001	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's request for additional information (RAI) dated October 30, 2001, regarding Section 2.1-1 of the Peach Bottom LRA.
December 14, 2001	In a letter signed by R. Anand to Exelon, the NRC staff provided the findings of its audit of the scoping and screening methodology use in the Peach Bottom LRA.
January 23, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the scoping and screening methodology discussed in Section 2.1.2 of the Peach Bottom LRA.
January 23, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the aging management of electrical and instrument and control discussed in Section 3.6 of the Peach Bottom LRA.
January 23, 2002	In a letter signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on December 26, 2001, to clarify information provided by Exelon in Section 3.2 of the Peach Bottom LRA.
January 28, 2002	In a letter signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on January 16, 2002, to clarify information provided by Exelon in Section 3.5 of the Peach Bottom LRA.
January 30, 2002	In a letter signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on January 3, 2002, to clarify information provided by Exelon in Section 4.3 of the Peach Bottom LRA.
February 6, 2002	In a letter signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on February 4, 2002 to clarify information provided by Exelon in Section 2.3 of the Peach Bottom LRA.
February 6, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the aging management of the reactor

	coolant system, the engineered safety feature systems, the auxiliary systems, and the steam and power conversion systems as discussed in Sections 3.1, 3.2, 3.3, and 3.4 of the Peach Bottom LRA.
February 7, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding time-limited aging analyses, identification of TLAAs, reactor vessel embrittlement, metal fatigue, and reactor vessel main steam nozzle cladding removal corrosion allowance as discussed in Sections 4.0, 4.1, 4.2, 4.3, and 4.7.1 of the Peach Bottom LRA.
February 28, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAI dated January 23, 2002, regarding Section 2.1.2 of the Peach Bottom LRA.
March 1, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the aging management of containment, structure, and component supports as discussed in Section 3.5 of the Peach Bottom LRA.
March 1, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the scoping and screening results for reactor coolant system, engineered safety features systems, and auxiliary systems as discussed in Sections 2.3.1, 2.3.2, and 2.3.3 of the Peach Bottom LRA.
March 6, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the aging management activities as discussed in Appendix B of the Peach Bottom LRA.
March 12, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the aging management activities as discussed in Appendix B of the Peach Bottom LRA.
March 12, 2002	In a letter to Exelon signed by R. Anand, the NRC staff requested additional information regarding the plant-level scoping, and screening results for mechanical, structures, component supports, and electrical and instrumentation and controls as discussed in the Sections 2.2, 2.3, 2.4, and 2.5 of the Peach Bottom LRA.
March 12, 2002	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on January 22, 2002, to clarify information provided by Exelon in Sections 3.3 and 3.4 of the Peach Bottom LRA.
March 13, 2002	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on January 22, 2002, to clarify information provided by Exelon in Sections 3.1and 4.1 of the Peach Bottom LRA.

April 5, 2002	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on February 20, 2002, to clarify information provided by Exelon in Section 2.0 of the Peach Bottom LRA.
April 29, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated January 23, 2002, regarding Section 3.6 of the Peach Bottom LRA.
April 29, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 12, 2002, regarding the Appendix B aging management activities discussed in the Peach Bottom LRA.
May 01, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated February 7, 2002, regarding Section 4.0 of the Peach Bottom LRA.
May 06, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 1, 2002, regarding Section 2.3 of the Peach Bottom LRA.
May 06, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated February 6, 2002, regarding Sections 3.1, 3.2, 3.3, and 3.4 of the Peach Bottom LRA.
May 14, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 6, 2002, regarding Appendix B aging management activities discussed in the Peach Bottom LRA.
May 21, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 1, 2002, regarding Section 3.5 of the Peach Bottom LRA.
May 21, 2002	In a letter signed by M. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated January 23, February 6, 2002, regarding RAI 2.1.2-3, 2.1.2-4, and 3.3-1.
May 22, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 12, 2002, regarding Section 2.0 of the Peach Bottom LRA.
May 31, 2002	In a NRC Region I letter to Exelon, signed by W. Lanning, the staff submitted Inspection Report 50-277/02-09, 50-278/02-09 concerning the scoping and screening of systems, structures, and components discussed in the Peach Bottom LRA.

June 10, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAIs dated March 12, 2002, regarding Section 4.2-7 of the Peach Bottom LRA.
July 18, 2002	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on June 17, 2002 to clarify information provided by Exelon concerning reactor vessel internals fatigue and embrittlement in Section 4.3.2 of the Peach Bottom LRA.
July 18, 2002	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on January 23 and March 12, 2002, to clarify information provided by Exelon concerning scoping and aging management of electrical and instrumentation and controls in Sections 2.5 and 3.6 of the Peach Bottom LRA.
July 30, 2002	In a letter signed by M.P. Gallagher, Exelon submitted its response to the NRC staff's RAI concerning fire protection activities, aging effects for carbon steel piping in an outdoor environment, and recovery path during station blackout system (SBO).
August 6, 2002	In a letter signed by P. Kuo, NRC informed Exelon that David L. Solorio was appointed Project Manager for the Peach Bottom LRA.
September 20, 2002	In a letter to Exelon signed by W. Dam, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on August 6 & 8, 2002, to clarify information provided by Exelon of the Peach Bottom LRA.
September 24, 2002	In a letter to Exelon signed by D. Solorio, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on July 23, August 19, and September 5 & 6, 2002, to clarify information provided by Exelon of the Peach Bottom LRA.
November 26, 2002	In a letter signed by M.P. Gallagher, Exelon submitted the response to Open Items and Confirmatory Items and Verification of Accuracy for Safety Evaluation Report (SER) Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 & 3.
December 19, 2002	In a letter signed by M.P. Gallagher, Exelon submitted the Amendment 1 to the Application for Renewal Operating License.
January 14, 2003	In a letter signed by M.P. Gallagher, Exelon submitted response to request for additional information related to license renewal.
January 29, 2003	In a letter signed by M.P. Gallagher, Exelon submitted the response to Teleconference Request to Modify Fuse Holder Inspection Program.

January 29, 2003	In a letter signed by M.P. Gallagher, Exelon submitted the response to Teleconference Request for Additional Clarification Related to SER Open Item 4.5.2-1 Response for Top Guide Inspection.
January 31, 2003	In a letter signed by M.P. Gallagher, Exelon submitted the response to request for additional information related to license renewal.
January 31, 2003	In a letter signed by M.P. Gallagher, Exelon submitted a list of future actions and a revision to the UFSAR Supplement for the Peach Bottom LRA.
February 3, 2003	In a letter to Exelon signed by R. Anand, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on November 14, 2002 to discuss information in Section 4.3.2, "Reactor Vessel Internals Fatigue and Embrittlement" of the Peach Bottom LRA.
February 4, 2003	In a letter to Exelon signed by D. Solorio, NRC issued a summary of a conference call between the staff and Exelon representatives. This conference call was held on December 4, 2002 to discuss matters related to the NRC staff review of the Peach Bottom Atomic Power Station LRA.
February 4, 2003	In a letter to Exelon signed by D. Solorio, NRC issued a summary of a teleconference between the staff and Exelon representatives. This teleconference was held on November 5, 2002 to discuss matters related to the NRC staff review of the Peach Bottom LRA.
February 5, 2003	In a letter signed by M.P. Gallagher, Exelon submitted a revised list of future actions and a revision to the UFSAR Supplement for the Peach Bottom LRA.
February 5, 2003,	In a letter to Exelon signed by D. Solorio, NRC issued a summary of a to documented the receipt of draft responses to open and confirmatory Items for the Safety Evaluation Report for the Peach Bottom Atomic Power Station License Renewal Application.
February 6, 2003	In a letter to Exelon signed by D. Solorio, NRC issued a summary of discussions regarding a draft list of future commitments related to the safety evaluation report for the Peach Bottom Atomic Power Station license renewal application.
March __, 2003	In a letter to Exelon signed by D. Solorio, NRC issued Errata to License Renewal Safety Evaluation Report For Peach Bottom Atomic Power Station, Units 2 and 3 (ADAMS Accession No. ML030800392).

APPENDIX B

REFERENCES

This appendix lists the references used in preparing the safety evaluation report on the review of the license renewal application for Peach Bottom Atomic Power Station, Units 2 and 3, under Docket Numbers 50-277 and 50-278.

AMERICAN CONCRETE INSTITUTE (ACI)

ACI 301, "Specifications for Structural Concrete for Buildings"

ACI 318-63, "Building Code Requirements for Reinforced Concrete"

AMERICAN SOCIETY OF MECHANICAL ENGINEERS (ASME)

ASME Boiler and Pressure Vessel Code, July 1989

ASME Boiler and Pressure Vessel Code, Section III, Rules for Construction of Nuclear Power Plant Components (through Summer 1979 addenda)

ASME Boiler and Pressure Vessel Code, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components

ASME Boiler and Pressure Vessel Code, Section XI, Appendix G (1995 edition through 1996 addenda)

AMERICAN SOCIETY FOR TESTING AND MATERIALS (ASTM)

ASTM A307, "Standard Specification for Carbon Steel Bolts and Steels, 60,000 psi Tensile Strength"

ASTM A325, "Standard Specification for Structural Bolts, Steel, Heat-Treated, 120 ksi and 105 ksi Minimum Tensile Strength"

ASTM A490, "Standard Specification for Heat-Treated Steel Structural Bolts, 150ksi Minimum Tensile Strength"

ASTM D975-1981, "Standard Specification for Diesel Fuel Oils"

AMERICAN WATER WORKS ASSOCIATION (AWWA)

AWWA C203, "AWWA Standard for Coal-Tar Protective Coatings and Linings for Steel Water Pipelines - Enamel and Tape - Hot Applied," 1966

BOILING WATER REACTOR VESSEL AND INTERNALS PROJECT (BWRVIP)

BWRVIP-05, "BWR RPV Shell Weld Inspection Recommendations," September 1995

BWRVIP-18, "Core Spray Internals Inspection and Flaw Evaluation Guidelines," July 1996

BWRVIP-25, "BWR Core Plate Inspection and Flaw Evaluation Guidelines," October 1999

BWRVIP-26, "Top Guide Inspection and Flaw Evaluation Guidelines," December 1996

BWRVIP-27, "Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines," April 1997

BWRVIP-38, "Shroud Support Inspection and Flaw Evaluation Guidelines," September 1997

BWRVIP-41, "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines," October 1997

BWRVIP-47, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," December 1997

BWRVIP-48, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines," March 1998

BWRVIP-49, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," March 1998

BWRVIP-74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," September 1999.

BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG-0313)," October 1999

BWRVIP-76, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," December 1999

BULLETINS (BL)

NRC BL-80-11, "Masonry Wall Design," May 1980

CODE OF FEDERAL REGULATIONS

10 CFR 50.34, "Contents of application; technical information," Section (a)(1)

10 CFR 50.48, "Fire Protection"

10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"

10 CFR 50.55a, "Codes and Standards"

10 CFR 50.60, "Acceptance Criteria for Fracture Prevention Measures for Light water Nuclear Power Reactors for Normal Operation"

10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events"

10 CFR 50.62, "Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants"

10 CFR 50.63, "Loss of All Alternating Current Power"

10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"

10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants"

10 CFR Part 50, Appendix G, "Fracture Toughness Requirements"

10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements"

10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions"

10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"

10 CFR Part 100, "Reactor Site Criteria"

ELECTRIC POWER RESEARCH INSTITUTE (EPRI)

EPRI NP-5461, "Component Life Estimation: LWR Structural Materials Degradation Mechanisms," September 1987

EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," Vols. 1 and 2, Project 2520-7, 1998

EPRI NSAC/202-L, "Recommendations for an Effective Flow-Accelerated Corrosion Program"

EPRI TR-103515, "BWR Water Chemistry Guidelines," BWRVIP-29

EPRI TR-103840 "BWR Containment License Renewal Industry Report; Revision 1" July 1994

EPRI TR-103842, "Class I Structures Industry Report"

EPRI TR-104873, "Methodologies and Processes to Optimize Environmental Qualification Replacement Internals," February 1996

EPRI TR-105747, "Guidelines for Reinspection of BWR Core Shrouds," BWRVIP-07, February 1996

EPRI TR-105759, "An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Evaluations"

EPRI TR-106092, "Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components in LWR Coolant Systems, " September 1997

EPRI TR-106740, "BWR Core Spray Internals and Flaw Evaluation Guidelines," BWRIVP-18, July 1996

EPRI TR-107079, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," Revision 2, BWRVIP-01, October 1996

EPRI TR-107285, "BWR Top Guide Inspection and Flaw Evaluation Guidelines," BWRVIP-26, December 1996

EPRI TR-107286, "BWR Standby Liquid Control System/Core Plate P Inspection and Flaw Evaluation Guidelines," BWRVIP-27, April 1997

EPRI TR- 107396, "Closed Cooling Water Chemistry Guidelines," October 1997

EPRI TR-107515, "Evaluation of Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal for the Calvert Cliffs Nuclear Power Plant"

EPRI TR-107521 related to void swelling

EPRI TR-107943, "Environmental Fatigue Evaluations of Representative BWR Components"

EPRI TR-108705, "BWR Vessel and Internals Project, Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection"

EPRI TR-108727, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," BWRVIP-47, December 1997

EPRI TR-108728, "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines," BWRVIP-41, October 1997

EPRI TR-108823, "BWR Shroud Support Inspection and Flaw Evaluation Guidelines," BWRVIP-38, September 1997

EPRI TR-108724, "Bessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines," BWRVIP-48, February 1998

EPRI TR-110356, "Evaluation of Environmental Thermal Fatigue Effects on Selected Components in a Boiling Water Reactor Plant"

EPRI TR-112214, "BWR Vessel and Internals Project, Proceedings: BWRVIP Symposium, November 12-13, 1998"

EPRI TR-113596, "BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines"

EPRI TR-114232, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines," BWRVIP-76, November 1999

EPRI TR-113596, "BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," BWRVIP-74, September 1999

EPRI TR-107396, "Closed Cooling Water Chemistry Guidelines"

GENERIC LETTERS (GLs)

NRC GL 79-20, "Information Requested on PVR Feedwater Lines"

NRC GL 85-20, "Resolution of Generic Issue 69: High Pressure Injection/Makeup Nozzle Cracking in Babcock and Wilcox Plants," November 11,1985

NRC GL 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," 1989

NRC GL 88-11, "NRC Position on Radiation Embrittlement of Reactor Vessel Materials and Its Impact on Plant Operations"

NRC GL 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment"

NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment"

NRC GL 90-05, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping," June 1990

NRC GL 91-17, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," October 1991

NRC GL 92-01, Revision 1, Supplement 1, "Reactor Vessel Structural Integrity," May 18, 1995

NRC GL 92-08, "Thermo-Lag 330-1 Fire Barriers," December 1992

NRC GL 96-04, "Boraflex Degradation in Spent Fuel Pool Storage Racks"

GENERIC SAFETY ISSUES (GSIs)

GSI-166, "Adequacy of the Fatigue Life of Metal Components"

GSI-168, "Environmental Qualification of Electrical Components"

GSI-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life"

INFORMATION NOTICES (INs)

NRC IN 87-65, "Lesson Learned from Regional Inspection of Applicant Actions in Response to IE Bulletin 80-11, 'Masonry Wall Design"

NRC IN 91-46, "Degradation of Emergency Diesel Generator Fuel Oil Deliver Systems," July 1991

NRC IN 92-20, "Inadequate Local Leak Rate Testing," March 1992

INSPECTION AND AUDIT REPORTS

Peach Bottom Atomic Power Station—NRC Inspection Report Nos. 50-277/02-09 and 50-278/02-09, May 31, 2002

Peach Bottom Atomic Power Station—NRC Inspection Report Nos. 50-277/02-10 and 50-278/02-10, September 27, 2002.

Peach Bottom Atomic Power Station—NRC Inspection Report Nos. 50-277/02-12 and 50-278/02-12, January 8, 2003.

Peach Bottom License Renewal Project Position Paper LR-P-002, "Systems and Structures Relied On To Demonstrate Compliance with 10 CFR 50.48, " Revision 1, Peach Bottom Atomic Power Station.

Peach Bottom License Renewal Project Position Paper LR-P-003, "Systems and Structures Required for Station Blackout," Revision 0, Peach Bottom Atomic Power Station.

Peach Bottom License Renewal Project Position Paper LR-P-005, "Identification of Nonsafety-Related SSCs Whose Failure Prevents Safety-Related SSCs From Fulfilling Their Safety-Related Function (Seismic II/I)," Revision 0, Peach Bottom Atomic Power Station.

Peach Bottom Procedure LR-C-14, "License Renewal Process," Revision 3, Peach Bottom Atomic Power Station.

Peach Bottom Procedure LR-C-14-3, "License Renewal Scoping and Screening Form," Revision 3, Peach Bottom Atomic Power Station.

Peach Bottom Procedure LR-C-14-3, "License Renewal SS Scoping Form: System 40 B, Reactor Building Ventilation System," Peach Bottom Atomic Power Station.

Peach Bottom Procedure LR-C-14-3, "License Renewal Scoping Form: System 70, Structures—Reactor Building," Peach Bottom Atomic Power Station.

Peach Bottom Procedure LR-C-14-3, "License Renewal SS Scoping Form: System 70, Structures—Turbine Building and Control Room Complex," Peach Bottom Atomic Power Station.

Peach Bottom, "License Renewal Component Screening Form for System 70, Structures Structural Commodities and Seals," Peach Bottom Atomic Power Station, July 26, 2001.

Peach Bottom License Renewal Project-Level Instruction (PLI) 001, "System Scoping and Realignment of CRL Components," Revision 0, Peach Bottom Atomic Power Station, April 18, 2001.

Peach Bottom License Renewal PLI-002, "License Renewal Drawings," Revision 1, Peach Bottom Atomic Power Station, September 4, 2001.

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APPENDIX C
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Information Systems Laboratory (ISL)	Plant-Level Scoping Results

Appendix D
Commitment Listing

During the review of Exelon's LRA by the NRC staff, the applicant made commitments to provide aging management programs to manage aging effects on structures and components prior to the expiration of its current operating license terms. The following table lists these commitments along with their implementation schedule for each unit.

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
1	Evaluate any age related degradation found during recirculation system ISI inspections for applicability to the NSR portions of the recirculation system that was included in the scope of license renewal for NSR/SR.	A.1.8, ISI Program	Prior to period of extended operation.	Clarification to SER OI 2.3.3.19.2-1, letter dated January 14, 2003.
2	Notify the NRC whether Integrated Surveillance Program per BWRVIP-78 or plant specific program will be implemented	A.1.12, Reactor Materials Surveillance Program	Prior to period of extended operation	Response to RAI 3.1-15, letter dated May 6, 2002 and license condition
3	Perform Inspection of carbon steel Component Supports (Other than ASME Class 1, 2, 3, and ASME Class MC component supports)	A.1.16, Maintenance Rule Structural Monitoring Program	Prior to period of extended operation and every 4 years thereafter.	Response to RAI 3.5-2, letter dated May 21, 2002
4	Perform Inspection of SBO structural components	A.1.16, Maintenance Rule Structural Monitoring Program	Prior to period of extended operation and every 4 years thereafter.	Response to RAI 2.5-1, letter dated May 22, 2002.
5	Perform periodic reviews of calibration test results of electrical cables used in LPRM and WRM Instrumentation circuits to identify potential existence of aging degradation	A.1.17, Electrical Cables not subject to 10CFR50.49 Environmental Qualification Requirements used in Instrumentation Circuits	On-going	Response to SER Open Item 3.6.1.2.2-1, letter dated November 26, 2002.
6	Perform inspection of outer sluice gates in the circulating water pump structure	A.2.5, Outdoor, Buried, and Submerged Component Inspection Activities	Prior to period of extended operation	Response to RAI 3.5-3, letter dated May 21, 2002.
7	Perform inspection of hazard barrier doors in a sheltered environment for loss of material	A.2.6, Door Inspection Activities	Prior to period of extended operation and every 4 years thereafter	Response to RAI 3.5-2.A, letter dated May 21, 2002 and RAI 2.6-1, letter dated April 29, 2002.

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
8	Perform inspection of RPV top guide	A.2.7, Reactor Pressure Vessel and Internals ISI Program	Prior to period of extended operation	Response to SER Open Item 4.5.2-1, letter dated January 14, 2003.
9	Perform ultrasonic testing to detect wall thinning at susceptible locations in the ESW system stagnant piping in ECCS rooms	A.2.8, GL 89-13 Activities	Prior to period of extended operation	UFSAR Supplement Appendix A.2.8 letter dated November 26, 2002
10	Perform one-time inspection of a cast iron fire protection component for selective leaching	A.2.9, Fire Protection Activities	Prior to period of extended operation	UFSAR Supplement Appendix A.2.9 letter dated November 26, 2002
11	Perform functional testing of sprinkler heads	A.2.9, Fire Protection Activities	Prior to year 50 of sprinkler service life	UFSAR Supplement Appendix A.2.9 letter dated November 26, 2002
12	Perform inspection of electrical conduits in outdoor environment	A.2.9, Fire Protection Activities	Prior to period of extended operation	RAI 3.5.3 response, letter dated May 21, 2002
13	Perform inspection of Susquehanna substation wooden pole	A.2.11, Susquehanna Substation Wooden Pole Inspection Activity	2003 and every 10 years thereafter	UFSAR Supplement Appendix A.2.11 letter dated November 26, 2002
14	Perform one-time inspection of wall thickness of selected torus piping	A.3.1, Torus Piping Inspection Activities	Prior to period of extended operation	UFSAR Supplement Appendix A.3.1 letter dated November 26, 2002
15	Perform inspection of PVC-insulated Fire Safe Shutdown cables in drywell	A.3.2, FSSD Cable Inspection Activity	Prior to period of extended operation	UFSAR Supplement Appendix A.3.2 letter dated November 26, 2002
16	Implement inspection program for Non-EQ accessible cables and connections, including fuse blocks	A.3.3, Non-EQ Accessible Cable Aging Management Activity	Prior to period of extended operation and every 10 years thereafter	RAI 3.6-1 response letter dated April 29, 2002; and SER Confirmatory Item 3.6.2.2.2-1, letter dated November 26, 2002.
17	Perform one-time piping inspection activities for standby liquid control system, auxiliary steam system, plant equipment and floor drain system, service water system, radiation monitoring system	A.3.4, One-Time Piping Inspection Activities	Prior to period of extended operation	RAI B.1.13-1 response dated May 14, 2002; and RAI 2.1.2-3 and 2.1.2-4 response dated May 21, 2002
18	Perform one-time inspection of susceptible locations for loss of material in fuel pool cooling system to verify effectiveness of fuel pool chemistry activities	A.3.4, One-Time Piping Inspection Activities	Prior to period of extended operation	Response to SER Open Item 3.0.3.6.2-1, letter dated November 26, 2002

Item	Commitment	UFSAR Supplement Location	Implementation Schedule	Source
19	Perform one-time inspection of carbon steel piping for loss of material in RPV instrumentation and Reactor Recirculation system	A.3.4, One-Time Piping Inspection Activities	Prior to period of extended operation	Response to SER Open Item 3.1.3.2.1-1, letter dated November 26, 2002.
20	Perform testing of inaccessible medium voltage cables	A.3.5, Inaccessible Medium Voltage Cables not subject to 10CFR50.49 Environmental Qualification Requirements	Prior to period of extended operation	SER Open Item 3.6.1.2.1-1 response dated November 20, 2002
21	Implement the final version of the fuse holder interim staff guidance when issued by the NRC.	A.3.6, Fuse holder Aging Management Activity	Prior to period of extended operation	Response to SER Confirmatory Item 3.6.2.2.2-1, letter dated January 29, 2003.
22	Implement fatigue management program	A.4.2, Fatigue Management Activities	Prior to period of extended operation	UFSAR Supplement Appendix A.4.2 letter dated November 26, 2002
23	Submit RPV P-T curves for 54 EFPY as license amendment	A.5.1.1.2, P-T Limit Curves	Prior to period of extended operation	RAI 4.2-5 response dated May 1, 2002
24	Submit RPV circumferential weld examination relief request for 60 years	A.5.1.1.3, Reactor Vessel Circumferential Weld Examination Relief	Prior to period of extended operation	UFSAR Supplement Appendix A.5.1.1.3 letter dated November 26, 2002 and response to RAI 4.2-6, letter dated May 1, 2002.
25	Implement BWRVIP-76 when approved by the NRC and accepted by BWRVIP Committee	A.2.7, Reactor Pressure Vessel and Internals ISI Program	Prior to period of extended operation	License Condition
26	Obtain NRC review and approval for an inspection program if used, to manage the effects of fatigue for RPV studs when CUF approaches 1.0	A.5.2.1, Reactor Vessel Fatigue	Prior to period of extended operation	UFSAR Supplement Appendix A.5.2.1 and RAI 4.3-1 response dated May 1, 2002
27	Perform plant specific calculations for locations identified in NUREG/CR-6260 for older vintage plants to manage the effects of environmental fatigue. If position is modified based on industry activities, obtain NRC approval prior to implementation.	A.5.2.4, Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping	Prior to period of extended operation	UFSAR Supplement Appendix A.5.2.4 and RAI 4.3-6 response dated May 1, 2002

NRC FORM 335 (2-89) NRCM 1102, 3201, 3202 — U.S. NUCLEAR REGULATORY COMMISSION **BIBLIOGRAPHIC DATA SHEET** *(See instructions on the reverse)*	1. REPORT NUMBER (Assigned by NRC, Add Vol., Supp., Rev., and Addendum Numbers, If any.) NUREG-1769
2. TITLE AND SUBTITLE Safety Evaluation Report Related to the license renewal of Peach Bottom Atomic Power Station, Units 2 and 3	3 DATE REPORT PUBLISHED MONTH: March YEAR: 2003 4 FIN OR GRANT NUMBER
5. AUTHOR(S) Senior Project Manager, David L. Solorio	6 TYPE OF REPORT Technical 7. PERIOD COVERED *(Inclusive Dates)*

8 PERFORMING ORGANIZATION - NAME AND ADDRESS *(If NRC, provide Division, Office or Region, U S Nuclear Regulatory Commission, and mailing address, if contractor, provide name and mailing address)*

Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001

9 SPONSORING ORGANIZATION - NAME AND ADDRESS *(If NRC, type "Same as above", if contractor, provide NRC Division, Office or Region, U S Nuclear Regulatory Commission, and mailing address.)*

Same as item 8 above

10 SUPPLEMENTARY NOTES

Docket Numbers 50-277 and 50-278

11. ABSTRACT *(200 words or less)*

This document is a safety evaluation report regarding the application to renew the operating licenses for Peach Bottom Atomic Power Station, Units 2 and 3. The application was filed by the Exelon Generation Company LLC, (Exelon) by letter dated July 2, 2001. The Office of Nuclear Reactor Regulation has reviewed the Peach Bottom Atomic Power Station, Units 2 and 3, license renewal application for compliance with the requirements of Title 10 of the Code of Federal Regulations, Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and prepared this report to document its findings.

In its July 2, 2001 submittal, Exelon requested renewal of the Peach Bottom, Units 2 and 3, operating licenses (License Nos. DPR-44 and DPR-56, respectively), which were issued under Section 104b of the Atomic Energy Act of 1954, as amended, for a period of 20 years beyond the current license expiration dates of August 8, 2013, and July 2, 2014, respectively. The Peach Bottom Atomic Power Station is a two-unit nuclear power plant located in York County and Lancaster County in southeastern Pennsylvania. Each unit consists of a General Electric boiling-water reactor nuclear steam supply system designed to generate 3514 megawatts thermal or approximately 1116 megawatts electric.

The NRC license renewal project manager for Peach Bottom, Units 2 and 3, is David Solorio. Mr. Solorio may be contacted by calling 301-415-1973 or by writing to the License Renewal and Environmental Impacts Program, U.S. Nuclear Regulatory Commission, Washington, DC 20555-001.

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