3.2 Aging Management of Engineered Safety Features

This section of the SER documents the staff's review of the applicant's AMR results for the ESF systems components and component groups associated with the following systems:

- containment
- standby gas treatment
- high pressure coolant injection
- residual heat removal
- core spray
- containment inerting
- containment atmosphere dilution

3.2.1 Summary of Technical Information in the Application

In LRA Section 3.2, the applicant provided AMR results for components. In LRA Table 3.2.1, "Summary of Aging Management Evaluations for Engineered Safety Features Evaluated in Chapter V of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the ESF systems components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.2.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging for the ESF systems components that are within the scope of license renewal and subject to an AMR will be adequately managed 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 performed an onsite audit, during the weeks of June 21 and July 2, 2004, of AMRs to confirm the applicant's claim that certain identified AMRs are consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff's audit evaluation are documented in the BFN audit and review report and are summarized in SER Section 3.2.2.1.

In the onsite audit, the staff also selected AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the acceptance criteria in SRP-LR Section 3.2.2.2, dated

July 2001. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.2.2.2.

In the onsite audit, the staff also conducted a technical review of the remaining AMRs that are not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects had been identified and evaluating whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.2.2.3. The staff's evaluation of its technical review is also documented in Section SER 3.2.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the ESF systems components.

Table 3.2-1, below, provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.2 that are addressed in the GALL Report.

Table 3.2-1 Staff Evaluation for Engineered Safety Features System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping, fittings and valves in emergency core cooling system (Item Number 3.2.1.1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue
Piping, fittings, pumps and valves in emergency core cooling system (Item Number 3.2.1.2)	Loss of material due to general corrosion	Water Chemistry Program; One-Time Inspection Program	Chemistry Control Program; One-Time Inspection Program	Consistent with GALL which recommends further evaluation (See Section 3.2.2.2.2)
Components in containment spray (PWR only), standby gas treatment system (BWR only), containment isolation, and emergency core cooling systems (Item Number 3.2.1.3)	Loss of material due to general corrosion	Plant-specific	One-Time Inspection Program; Chemistry Control Program; Systems Monitoring Program	See Section 3.2.2.2.2

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Containment isolation valves and associated piping (Item Number 3.2.1.6)	Loss of material due to microbiologically influenced corrosion (MIC)	Plant-specific	Open-Cycle Cooling Water Program	See Section 3.2.2.2.4
Seals in standby gas treatment system (Item Number 3.2.1.7)	Changes in properties due to elastomer degradation	Plant-specific	N/A	See Section 3.2.2.2.5
Drywell and suppression chamber spray system nozzles and flow orifices (Item Number 3.2.1.9)	Plugging of nozzles and flow orifices by general corrosion products	Plant-specific	N/A	See Section 3.2.2.2.7
External surface of carbon steel components (Item Number 3.2.1.10)	Loss of material due to general corrosion	Plant-specific	One-Time Inspection Program; Chemistry Control Program; Systems Monitoring Program	See Section 3.2.2.2.2
Piping and fittings of CASS in emergency core cooling systems (Item Number 3.2.1.11)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS Program	N/A	Not Applicable BFN does not require a thermal aging embrittlement of CASS AMP
Components serviced by open-cycle cooling system (Item Number 3.2.1.12)	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-Cycle Cooling Water System Program	Open-Cycle Cooling Water System Program	Consistent with GALL which recommends no further evaluation (See Section 3.2.2.1)
Components serviced by closed-cycle cooling system (Item Number 3.2.1.13)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System Program	Closed-Cycle Cooling Water System Program	Consistent with GALL which recommends no further evaluation (See Section 3.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Emergency core cooling system valves and lines to and from high pressure coolant injection and reactor core isolation cooling pump turbines (Item Number 3.2.1.14)	Wall-thinning due to flow-accelerated corrosion	Flow Accelerated Corrosion Program	Flow Accelerated Corrosion Program	Consistent with GALL which recommends no further evaluation (See Section 3.2.2.1)
Pumps, valves, piping and fittings in emergency core cooling system (Item Number 3.2.1.16)	Crack initiation and growth due to SCC and IGSCC	Water Chemistry Program; BWR Stress Corrosion Cracking Program	Chemistry Control Program; BWR Stress Corrosion Cracking Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.2.2.1))
Closure bolting in high-pressure or high-temperature systems (Item Number 3.2.1.18)	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and/or SCC	Bolting Integrity Program	Bolting Integrity Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.2.2.1)

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.2.2.1, involves the staff's review of the AMR results for components in the ESF systems that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.2.2.2, involves the staff's review of the AMR results for components in the ESF systems that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.2.2.3, involves the staff's review of the AMR results for components in the ESF systems that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the ESF systems components is documented in SER Section 3.0.3.

3.2.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Not Recommended

<u>Summary of Technical Information in the Application</u>. In LRA Section 3.2.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the ESF systems components:

- Bolting Integrity Program
- Buried Piping and Tanks Inspection Program
- Chemistry Control Program
- One-Time Inspection Program

- Open-Cycle Cooling Water System Program
- Selective Leaching of Materials Program
- Systems Monitoring Program
- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program
- BWR Stress Corrosion Cracking Program
- Flow-Accelerated Corrosion Program

Staff Evaluation. In LRA Tables 3.2.2-1 through 3.2.2-7, the applicant provided a summary of AMRs for the ESF systems components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report which the applicant stated are consistent with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated the AMR was consistent with the GALL Report.

Note A indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated that the component for the AMR line item is different from, but consistent with, the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated that the component for the AMR line item is different from, but consistent with, the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicated that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but that a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in its BFN audit and review report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluation is discussed below.

For aging management evaluations that the applicant stated are consistent with the GALL Report and for which further evaluation is not recommended, the staff conducted its audit to determine if the applicant's reference to the GALL Report in the LRA is acceptable.

The staff reviewed the LRA to confirm that the applicant (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the ESF system components that are subject to an AMR.

The staff identified that LRA Table 3.2.2.5 is not consistent with the GALL Report Item IVC1.3-c. The staff asked the applicant to explain this inconsistency. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the correct AMPs for LRA Table 3.2.2.5 are the Chemistry Control Program and the BWR Stress Corrosion Cracking Program (instead of the One-Time Inspection Program). The staff found this acceptable because it is consistent with the GALL Report.

On the basis of its audit, the staff determined that for AMRs not requiring further evaluation, as identified in LRA Table 3.2.1 (Table 1), the applicant's references to the GALL Report are acceptable and no further staff review is required.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concluded that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR54.21(a)(3).

3.2.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation Is Recommended

Summary of Technical Information in the Application. In LRA Section 3.2.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the ESF systems. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general corrosion
- local loss of material due to pitting and crevice corrosion
- local loss of material due to microbiologically influenced corrosion (MIC)
- changes in properties due to elastomer degradation
- local loss of material due to erosion
- buildup of deposits due to corrosion
- quality assurance for aging management of NSR components

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it had adequately addressed the issues that had been further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.2.2.2. Details of the staff's audit are documented in the staff's audit and review report. The staff's evaluation of the aging effects is discussed in the following sections.

For some line items in LRA Tables 3.2.2.1 through 3.2.2.7 that are identified to be consistent with the GALL Report, the applicant cross-referenced specific line items in LRA Tables 3.1.1 and 3.2.1, for which the GALL Report recommends further evaluation. Where the GALL Report recommends further evaluation, the staff reviewed the applicable further evaluations provided in LRA Sections 3.1.2.2 and 3.2.2.2 against the criteria provided in SRP-LR Sections 3.1.2.2 and 3.2.2.2, respectively.

The following subsections provide the staff's assessment of the applicant's further evaluations in LRA Section 3.2.2.2 against the criteria provided in SRP-LR Section 3.2.2.2.

The staff's assessment of the applicant's further evaluations in LRA Section 3.1.2.2 is provided in SER Section 3.1.2. Where credited, the assessment also considered applicability to aging management of the ESF systems.

3.2.2.2.1 Cumulative Fatigue Damage

Consistent with the SRP-LR, the applicant references LRA Section 4.3.3. Cumulative fatigue damage is a TLAA, and is evaluated in SER Section 4.

3.2.2.2.2 Loss of Material Due to General Corrosion (LRA Section 3.2.2.2.2)

The applicant references LRA Table 3.2.1, items 3.2.1.3 and 3.2.1.10, to address loss of material due to general corrosion for ESF components in containment isolation, standby gas treatment, residual heat removal and containment inerting systems and also for RCS components. These Table 1 items reference LRA Section 3.2.2.2.2 for further evaluation. The staff reviewed LRA Section 3.2.2.2.2 against the criteria in SRP-LR Section 3.2.2.2.2.

In LRA Section 3.2.2.2.2, the applicant addressed loss of material due to general corrosion of the portions of ESF systems piping filled with treated water or air/gas, and the external surfaces of carbon steel components.

SRP-LR Section 3.2.2.2.2 states that the management of loss of material due to general corrosion of pumps, valves, piping, and fittings associated with some of the BWR emergency core cooling systems [high pressure coolant injection, reactor core isolation cooling, high pressure core spray, low pressure core spray, low pressure coolant injection (residual heat removal)] and with lines to the suppression chamber and to the drywell and suppression chamber spray system should be further evaluated. The existing AMP relies on monitoring and control of primary water chemistry to mitigate degradation; however, control of primary water chemistry does not preclude loss of material due to general corrosion at locations of stagnant flow conditions. Therefore, verification of the effectiveness of the Chemistry Control Program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material due to general corrosion to verify the effectiveness of the Chemistry Control Program. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly such that the component's intended function will be maintained during the period of extended operation. Also, the GALL Report recommends further evaluation on a plant-specific basis to ensure that the aging effect on the external surfaces of BWR carbon steel components is adequately managed.

In the LRA Section 3.2.2.2.2, the applicant stated that loss of material due to general corrosion of the portions of ESF systems filled with treated water is managed by the Chemistry Control Program and the One-Time Inspection Program. The One-Time Inspection Program is used to verify the effectiveness of the Chemistry Control Program for managing the loss of material due to general corrosion. Loss of material due to general corrosion of the air/gas portions of these systems is managed by the One-Time Inspection Program for internal surfaces.

General corrosion of all external surfaces of carbon steel components is managed by the plant-specific Systems Monitoring Program. The staff reviewed the BFN procedure (NEDP-20, rev. 3, "Conduct of the Engineering Organization," September 9, 2002) for conducting system monitoring during system walkdowns. The walkdown encompasses all or part of the total accessible system, such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of carbon steel components.

On the basis of its review of the Chemistry Control Program, One-Time Inspection Program, and the Systems Monitoring Program, the staff found that the applicant had conducted an acceptable AMR for management of loss of material due to general corrosion, consistent with the recommendations in the GALL Report.

3.2.2.2.3 Local Loss of Material due to Pitting and Crevice Corrosion

The applicant references LRA Table 3.2.1, item 3.2.1.5, to address loss of material due to pitting and crevice corrosion for ESF components in containment and containment inerting systems and also for RCS components. The applicant's further evaluation is in LRA Section 3.2.2.2.3. The staff reviewed LRA Section 3.2.2.2.3 against the criteria in SRP-LR Section 3.2.2.2.3.

In the LRA Section 3.2.2.2.3, the applicant addressed local loss of material from pitting and crevice corrosion that could occur in the ESF systems and associated piping filled with treated water or air/gas.

SRP-LR Section 3.2.2.2.3 states that the management of local loss of material due to pitting and crevice corrosion of pumps, valves, piping, and fittings associated with some of the BWR emergency core cooling system piping and fittings [high pressure coolant injection, reactor core isolation cooling, high pressure core spray, low pressure core spray, low pressure coolant injection (residual heat removal)] and with lines to the suppression chamber and to the drywell and suppression chamber spray system should be evaluated further. The existing AMP relies on monitoring and control of primary water chemistry to mitigate degradation. However, control of coolant water chemistry does not preclude loss of material due to crevice and pitting corrosion at locations of stagnant flow conditions. Therefore, verification of the effectiveness of the Chemistry Control Program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage the loss of material due to pitting and crevice corrosion to verify the effectiveness of the Chemistry Control Program. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is not occurring or an aging effect is progressing very slowly so that the component's intended function will be maintained during the period of extended operation.

In the LRA Section 3.2.2.2.3, the applicant stated that loss of material due to pitting and crevice corrosion of the portions of ESF systems filled with treated water is managed by the Chemistry Control Program and the One-Time Inspection Program. The One-Time Inspection Program is used to verify the effectiveness of the Chemistry Control Program for managing the loss of material due to pitting and crevice corrosion. Loss of material due to pitting and crevice corrosion of the air/gas portions of these systems is managed by the One-Time Inspection Program for internal surfaces.

On the basis of its review of the Chemistry Control Program and One-Time Inspection Program, the staff found that the applicant had conducted an acceptable AMR for management of loss of material due to pitting and crevice corrosion, consistent with the recommendations in the GALL Report.

3.2.2.2.4 Local Loss of Material due to Microbiologically Influenced Corrosion

The staff reviewed LRA Section 3.2.2.2.4 against the criteria in SRP-LR Section 3.2.2.2.4. The applicant references LRA Table 3.2.1, item 3.2.1.6, to address loss of material due to MIC for ESF components in containment and containment inerting systems.

SRP-LR Section 3.2.2.2.4 states that local loss of material due to MIC could occur in containment isolation valves and associated piping in systems that are not addressed in other chapters of the GALL Report. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed.

LRA Section 3.2.2.2.4 states that the applicant considers MIC to be an aging mechanism for systems in a raw water environment. BFN has no systems containing raw water that penetrate primary containment. Several raw water systems penetrate secondary containment. BFN utilizes the Open-Cycle Cooling Water Program to manage the aging effects that could be caused by MIC in these systems.

On the basis of its review of the Open-Cycle Cooling Water Program, the staff found that the applicant had conducted an acceptable AMR for management of loss of material due to MIC, consistent with the recommendations in the GALL Report.

3.2.2.2.5 Changes in Properties due to Elastomer Degradation

The staff reviewed LRA Section 3.2.2.2.5 against the criteria in SRP-LR Section 3.2.2.2.5. In LRA Section 3.2.2.2.5, the applicant described its AMR for change in material properties due to elastomer degradation, for seals in ductwork and filters associated with the standby gas treatment (SGT) system. The applicant stated that the normal operating temperature of the SGT system is less than the defined limits for hardening and loss of strength of installed elastomers. This statement is not consistent with the criteria in SRP-LR Section 3.2.2.2.5.

LRA Table 3.2.2.2, which includes the AMR results for elastomer seals in the SGT system, does not reference LRA Table 1, Item 3.2.1.7. Instead, the applicant identified the AMR for these components to be not consistent with the GALL Report, and concluded that aging management is not required. The staff evaluation of the applicant's AMR results for elastomers in the SGT system was not conducted during the onsite audit.

3.2.2.2.6 Local Loss of Material due to Erosion

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.2.2.2.7 Buildup of Deposits due to Corrosion

The staff reviewed LRA Section 3.2.2.2.7 against the criteria in SRP-LR Section 3.2.2.2.7. In LRA Section 3.2.2.2.7, the applicant addressed the plugging of components due to general corrosion that could occur in the spray nozzles and flow orifices of the drywell and suppression chamber spray system. The applicant stated that spray nozzles are brass and are not susceptible to general corrosion, and that there are no orifices susceptible to general corrosion that are occasionally wetted in the ESF systems.

The applicant does not reference LRA Table 1, Item 3.2.1.9 in any of the AMR tables for the ESF systems. The applicant concluded that, since the spray nozzles and orifices are not susceptible to general corrosion that may cause plugging, aging management is not required. The staff found the applicant's AMR results to be acceptable, on the basis that the subject components are not susceptible to general corrosion.

3.2.2.2.8 Quality Assurance for Aging Management of Non-Safety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's QA program.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant demonstrated that the effects of aging will be adequately managed 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).

3.2.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.2.2.1 through 3.2.2.7, the staff reviewed additional details of the results of the AMRs for material, environment, AERM, and AMP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Tables 3.2.2.1 through 3.2.2.7, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report, and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation.

The staff requested the applicant to provide additional information on the issues described in the following general RAIs. These RAIs, the applicant's responses, and the staff's evaluation of the responses are described below.

In RAI 3.2-1, dated November 18, 2004, the staff stated that in LRA Tables 3.2.2.1 through 3.2.2.7, carbon and low-alloy steel bolting in an inside air (external) or outside air (external) environment is not identified with any AERMs. The applicant indicated that this is because BFN does not use high yield strength bolting. Therefore, the staff requested that the applicant discuss the specific material grade used for the bolting in each of the associated systems, and justify the basis for concluding that crack initiation/growth due to SCC is not a concern for the bolting during the period of extended operation.

In its letter dated December 16, 2004, the applicant responded as follows:

> The identified aging management program is the Bolting Integrity Program. As noted, a cracking aging effect is not identified because high yield bolting materials (yield strength above 150 ksi) were not identified and plant operating experience does not indicate an adverse history of bolt cracking. Stress corrosion cracking (SCC) of bolted closures and fasteners is a condition of high yield strength bolting material where a fastener that is statically loaded well below its yield strength can experience sudden failure. SCC occurs through the combination of high stress (both applied and residual tensile stresses), a corrosive environment, and a susceptible material. SCC of high yield strength bolted closures in BWRs requires a corrosive environment typically attributed to leakage of pressure boundary joints or exposure to wetted ambient environments (indoor, outdoor, buried and submerged) and the use of thread lubricant containing MoS_2 (molybdenum disulfide).
>
> The use of MoS_2 thread lubricant is not allowed by site and engineering procedures. Therefore, any maintenance on this mechanical equipment would result in the use of non-MoS_2 thread lubricant. Loss of bolting function due to SCC of bolted joints of vendor-supplied mechanical equipment is not expected and no aging management is required for the period of extended operation.

The staff concluded that loss of bolting function due to SCC of bolted joints of vendor-supplied mechanical equipment is not expected and that aging management is not required for these components for the period of extended operation. On the basis of the applicant's response, the staff's concern described in RAI 3.2-1 is resolved.

In RAI 3.2-2, dated November 18, 2004, the staff stated that in LRA Tables 3.2.2.1 through 3.2.2.4, 3.2.2.6, and 3.2.2.7, nickel-alloy bolting in inside air (external) environments were not identified with any AERMs. The applicant invoked industry guidance/experience to support the analysis. Therefore, the staff requested the applicant to provide a detailed discussion of the air environment involved, and to justify the basis for concluding that there are no AERMs under such material/environment combinations. The staff also requested information on the stated industry guidance.

In its letter dated December 16, 2004, the applicant responded as follows:

> The nickel-alloy bolting in the Containment Isolation System was evaluated for wear and no applicable wear mechanism was identified for non-RCPB components. Therefore, wear is not an aging mechanism that requires management for the period of extended operation for the Containment Isolation System. Nickel-alloy bolting, similar to stainless steel bolting, is subject to cracking under severe environmental conditions such as high temperature and being buried or submerged (potentially, depending on type of external water). Nickel-alloy bolting in the Containment Isolation System is not subject to this severe environment; therefore, cracking was not identified.

The copper-alloy components exposed to an inside air (external) environment were evaluated individually to determine where condensation or periodic wetting could occur. The identified aging effects were then determined based on the particular copper alloy present and whether condensation or periodic wetting could occur. Based on this evaluation, there were no instances where copper alloys components with > 15% Zn were subjected to an aggressive environment or condensation/periodic wetting. Therefore, no aging effects that require management during the period of extended operation were identified for the copper alloy components in the subject tables. A summary description of the industry guidance (i.e., when industry guidance is referenced was provided in the EPRI Technical Report 1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools") for copper alloys.

The applicant response dated December 16, 2004, contains detailed information for copper alloys. On the basis of the applicant's response, the staff's concern described in RAI 3.2-2 is resolved.

In RAI 3.2-3, dated November 18, 2004, the staff stated that in LRA Table 3.2.2.1, material carbon and low-alloy steel, component type valves in a treated water (internal) environment are not identified with any AERMs. The staff noted that the component, material and environment combination for this component is similar to that identified in the GALL Report, Item V.C.1-a, which recommends a plant-specific AMP to be evaluated for the identified aging effects. Therefore, the staff requested that the applicant explain why the aging effects identified in the GALL Report, such as loss of material due to general, pitting, and crevice corrosion, are not applicable to these components.

In its response, by letter dated December 16, 2004, the applicant stated that the reason for the line entries that indicate no aging effects is an attempt to ensure completeness of GALL Report comparison. For carbon and low-alloy steel valves in a treated water environment, rows 78, 79, and 80 of LRA Table 3.2.2.1 address the applicable aging mechanisms. The applicable GALL Volume 2 line item was determined to be V.C.1-a. which lists five aging effects: general, pitting, crevice, MIC, and biofouling. For a treated water environment, the BFN AMR determined that microbiologically influenced corrosion and biofouling did not require management for the period of extended operation. However, the BFN AMR determined that in addition to the aging mechanisms identified in the GALL Report, galvanic corrosion was also applicable. This was documented in the AMR as:

Galvanic corrosion – Yes, with notes H and 3
General corrosion – Yes, consistent with GALL
Pitting corrosion – Yes, consistent with GALL
Crevice corrosion – Yes, consistent with GALL
Microbiologically influenced corrosion – No, see below
Biofouling – No, see below

The first aging mechanism is documented in row 78 with notes H and 3. The next three aging mechanisms, which are consistent with the GALL Report, form the basis for row 80 of LRA Table 3.2.2.1. The last two aging mechanisms are documented in row 79 of LRA Table 3.2.2.1 with a note 5 was incorrect which should be 4. Note 4, stated that based on system design and operating history, MIC and biofouling were determined to be not applicable to the treated water portions of this system.

The staff found the above applicant's response to have adequately clarified the fact that loss of material due to general, pitting, and crevice (in addition to galvanic) corrosion has indeed been identified in its AMR. Therefore, the staff's concern described in RAI 3.2-3 is resolved.

In RAI 3.2-3, dated November 18, 2004, the staff stated that in LRA Table 3.2.2.3, the applicant did not identify elastomer flexible connectors in an air/gas (internal) environment with any AERMs. The applicant stated that there are no applicable aging effects for this material/environment combination and believes that this is consistent with industry guidance. Therefore, the staff requested additional information to justify the basis for concluding that there are no AERMs under such material/environment combinations, including an insight into the industry guidance.

In its response, by letter dated December 16, 2004, the applicant stated that the issue involved aging effects due to material property changes and cracking of the rubber fabric reinforced (elastomer) flexible connectors upstream and downstream of the gland seal condenser blower (gland exhauster) in an air/gas environment. These effects are caused by exposure to ultraviolet radiation, oxygen, ozone, heat, and radiation. The applicant stated that the elastomer degradation due to these aging mechanisms are not significant because the ultraviolet radiation and ozone effects to the internal surfaces of the components are negligible. The LRA does identify elastomer degradation due to ultraviolet radiation and ozone for the external surfaces of these components.

The applicant further stated that maximum temperature rating for rubber is 130 °F per industry guidance. During normal operation, the temperature of the flexible connectors is significantly less than 130 °F; therefore, degradation from thermal exposure is not identified as an aging mechanism requiring management for the period of extended operation. The applicant further stated that the dose threshold for radiation degradation of rubber is 10^7 rads. The ionizing radiation the flexible connectors will receive is negligible (much less than 10^7 rads); therefore, degradation from ionizing radiation is not identified as an aging mechanism requiring management for the period of extended operation.

The staff found the applicant's basis for not identifying any aging effects for the elastomer flexible connectors to be acceptable. Therefore, the staff's concern described in RAI 3.2-4 is resolved.

In RAI 3.2-5, dated November 18, 2004, the staff stated that in LRA Table 3.2.2.5, the applicant stated that aluminum-alloy fittings in a treated water (internal) environment are identified as being susceptible to crack initiation/growth due to SCC and loss of material due to crevice and pitting corrosion. Therefore, the staff requested additional information to explain why loss of material due to general and galvanic corrosion is not identified as a potential AERM during the period of extended operation. The applicant was also requested to explain how the Chemistry Control Program, in association with the One-Time Inspection Program, is used to manage the identified aging effects.

In its response, by letter dated December 16, 2004, the applicant stated that, per industry guidance, aluminum and aluminum-based alloys in a treated water environment are not susceptible to loss of material due to general corrosion. In addition, the applicant stated that the aluminum fittings in Table 3.2.2.5 are the flanges off the 24-inch diameter condensate supply header within the core spray system. An electrically insulating rubber gasket is used to electrically separate the aluminum flanges from more cathodic materials, such as copper or stainless or carbon steels. Based on that, the staff concurred with the applicant's conclusion that galvanic corrosion is not a concern for this configuration for aluminum fittings in a treated water environment for the core spray system.

The applicant also stated that the main objective of the Chemistry Control Program is to minimize loss of material due to general, crevice, and pitting corrosion and crack initiation and growth caused by SCC. Corrosion and cracking of aluminum alloys in treated water is managed by maintaining oxygen, chlorides, and sulfates within the limits of the Chemistry Control Program. The specific chemistry limits are the same as the limits used to manage aging of carbon/low-alloy and stainless steel components in a treated water environment. The applicant stated that the use of the Chemistry Control Program is consistent with industry practice as identified in its past precedence review. The staff accepted the Chemistry Control Program for primary systems program and its evaluation of this program is documented in SER Section 3.0.3.2.2. GALL AMP XI.M32, "One-Time Inspection," is used to verify the Chemistry Control Program's effectiveness, as recommended by the GALL Report. The staff considered that the applicant had adequately addressed its concerns stated in the RAI; therefore, RAI 3.2-5 is resolved.

In RAI 3.2-6, dated November 18, 2004, the staff stated that in LRA Table 3.2.2.5 polymer tubing in an air/gas (internal) or inside air (external) environment is not identified with any AERMs. Therefore, the staff requested the applicant to provide a discussion of the air environment involved, and justify the basis for concluding that there are no AERMs under such material/environment combinations.

In its response, by letter dated December 16, 2004, the applicant stated that polymer tubing in the core spray system is the Tygon (polyvinyl chloride) tube off the closed drain valve downstream of the drain dirt separator (trap) used in the keep fill system (shown on drawing 2-47E814-1). Under normal operating conditions, the internal and external environment is atmospheric air. The applicant stated that unlike metals, thermoplastics do not display corrosion rates. Rather than depending on an oxide layer for protection, they depend on chemical resistance to the environment to which they are exposed. Therefore, acceptability for the use of thermoplastics in an air/gas environment is a design driven criterion. Once the appropriate material is chosen, the system will have no aging effects.

The applicant stated that the temperature and radiation damage threshold limits are 200 °F and 2×10^7 rads, respectively. Neither of these limits is challenged in the LRA where Tygon is utilized; however, Tygon may be degraded when exposed to air and ultraviolet radiation; therefore, the applicant stated that for the external surface of the Tygon tubing, degradation should have been identified in the LRA by revising the line item to include "Hardening and loss of strength due to polymer degradation (ultraviolet radiation)" as an aging effect and an aging mechanism. The Systems Monitoring Program will be used to manage the aging effect.

Based on the above, the staff considered that the applicant had adequately addressed its concerns; therefore, RAI 3.2-6 is resolved.

3.2.2.3.1 Containment System – Summary of Aging Management Evaluation – Table 3.2.2.1

The staff reviewed LRA Table 3.2.2.1, which summarizes the results of AMR evaluations for the containment system component groups.

In LRA Table 3.2.2.1, the applicant identified no aging effects in containment system component groups made of aluminum alloys exposed to inside/outside air in the ductwork and heat exchangers or carrying air/gas in the ductwork; carbon and low-alloy steel piping/fittings embedded or encased in concrete; copper-alloy piping carrying air/gas; glass (fittings) exposed to air/gas, treated water, or inside air; and nickel-alloy fittings, stainless steel fittings, and zinc-alloy ductwork exposed to air/gas. These environment's conditions are not identified in the GALL Report for these components and materials. On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion of low-alloy steel requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In LRA Table 3.2.2.1, the applicant identified that the loss of material due to general, crevice, pitting and galvanic corrosion in carbon/low-alloy steel, nickel alloys and stainless steel piping and fittings in treated water are managed by the Chemistry Control Program and One-Time Inspection Program. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on BWRVIP-79 to prevent loss of material from general, pitting, crevice or galvanic corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program needs to be performed to ensure that corrosion is not occurring. The one-time inspection of selected components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In LRA Table 3.2.2.1, heat exchanger components made of carbon/low-alloy steel and exposed to raw water are susceptible to loss of material due to biofouling, MIC, crevice, galvanic, general, and pitting corrosion; and heat exchanger components made of copper alloys and exposed to raw water are susceptible to fouling due to biological particulate build-up and loss of material due to selective leaching, biofouling, MIC, crevice and pitting corrosion. The applicant credited the Selective Leaching of Materials Program and Open-Cycle Cooling Water System Program to manage these aging effects. The latter AMP, in accordance with the guidelines of GL 89-13, includes managing aging effects by condition monitoring (system and component testing, visual inspections, and NDE testing), and by preventive actions (biocide treatment and filtering to prevent loss of material due to MIC and biofouling and flow blockage and reduction of heat transfer due to biological and particulate fouling). The staff found this acceptable.

Aluminum-alloy heat exchangers carrying air/gas; carbon/low-alloy steel piping/fittings and heat exchangers exposed to air/gas; and copper-alloy components of heat exchangers exposed to air/gas are susceptible to loss of material due to general pitting, crevice corrosion, and fouling due to particulate build-up. In LRA Table 3.2.2.1, the applicant credited the One-Time

Inspection Program to manage these aging effects. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

In LRA Table 3.2.2.1, piping and fittings made of carbon/low-alloy steel buried in soil are susceptible to loss of material due to MIC, crevice, general, and pitting corrosion. The applicant credited the Buried Piping and Tanks Inspection Program to manage this aging effect. This AMP involves preventive measures to mitigate corrosion (external coatings and wrappings have been applied in accordance with standard industry practices) and condition monitoring to manage the effects of corrosion. Buried piping is inspected when excavated for any reason, typically for maintenance. The inspections are performed as part of the 10 CFR 50.65, "Maintenance Rule Program." The inspections provide for determination of degradation due to the loss of, or damage to, the protective coatings and wraps used for corrosion control on buried pipe external surfaces. The inspections also include connections and joints for signs of separation, signs of environmental degradation, signs of leakage, and appreciable settlement between piping segments. The staff found this inspection program acceptable for managing the aging effect of loss of material.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.2 Standby Gas Treatment System – Summary of Aging Management Evaluation – Table 3.2.2.2

The staff reviewed LRA Table 3.2.2.2, which summarizes the results of AMR evaluations for the standby gas treatment system component groups.

In LRA Table 3.2.2.2, the applicant identified no aging effects in standby gas treatment system component groups made of aluminum-alloy ductwork, copper-alloy tubing, stainless steel fittings, and zinc-alloy ductwork. All of these components carry air/gas and their external surface is exposed to inside air. These environment conditions are not identified in the GALL Report for these components and materials. On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion of low-alloy steel requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In LRA Table 3.2.2.2, piping and fittings made of carbon/low-alloy steel buried in soil are susceptible to loss of material due to MIC, crevice, general, and pitting corrosion. The applicant credited the Buried Piping and Tanks Inspection Program to manage this aging effect. This AMP involves preventive measures to mitigate corrosion (external coatings and wrappings have been applied in accordance with standard industry practices) and condition monitoring to manage the effects of corrosion. Buried piping is inspected when excavated for any reason, typically for maintenance. The inspections are performed as part of the 10 CFR 50.65, "Maintenance Rule Program." The inspections provide for determination of degradation due to the loss of, or damage to, the protective coatings and wraps used for corrosion control on buried pipe external surfaces. The inspections also include connections and joints for signs of separation, signs of environmental degradation, signs of leakage, and appreciable settlement between piping segments. The staff found this inspection program acceptable for managing the aging effect of loss of material.

Carbon and low-alloy steel and cast iron/cast iron alloy piping, fittings, and valves exposed to air/gas are susceptible to loss of material due to general corrosion. In LRA Table 3.2.2.2, the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

Carbon and low-alloy steel and cast iron/cast iron alloy piping, fittings, and valves external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. The system walkdown encompasses all or part of the total accessible system, such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.3 High Pressure Coolant Injection System – Summary of Aging Management Evaluation – Table 3.2.2.3

The staff reviewed LRA Table 3.2.2.3, which summarizes the results of AMR evaluations for the high pressure coolant injection (HPCI) system component groups.

In LRA Table 3.2.2.3, the applicant identified no aging effects in HPCI system component groups made (1) out of carbon and low-alloy steel piping and fittings exposed to inside air (external surface) and carrying lube oil, cast iron alloy pumps and valves carrying lube oil; (2) copper-alloy tubing/fittings carrying air/gas and lube oil; (3) glass (fittings) exposed to air/gas and lube oil; and (4) nickel-alloy flexible connectors and stainless steel fittings exposed to inside air (external). These environment conditions are not identified in the GALL Report for these components and materials. On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In LRA Table 3.2.2.3, the applicant identified that the loss of material due to general, crevice, pitting and galvanic corrosion in carbon/low-alloy steel piping, fittings, and various components, cast iron and cast iron alloy pumps, copper-alloy condensers and heat exchangers, nickel-alloy flexible connectors, and stainless steel piping, fittings, tubing, and valves in treated water are managed by the Chemistry Control Program and One-Time Inspection Program. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on BWRVIP-79 to prevent loss of material from general, pitting, crevice or galvanic corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program needs to be performed to ensure that corrosion is not occurring. The one-time inspection of selected components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and the component's intended function will be maintained during the period of extended operation.

In components made from cast iron and cast iron alloys and copper alloy, selective leaching takes place when these components are exposed to corrosion-inhibited treated water, oxygenated and de-oxygenated treated water. In LRA Table 3.2.2.3, the applicant identified Selective Leaching of Materials Program to manage loss of material due to selective leaching in cast iron pumps and copper-alloy condensers exposed to treated water. The applicant's selective leaching program relies on visual inspections and hardness measurements on selected components susceptible to selective leaching. On the basis of industry operating experience with this material and environment, the staff found this acceptable.

Cast iron/cast iron alloy fittings and carbon and low-alloy steel external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. Elastomer flexible connections exposed to inside air are subject to elastomer degradation due to ultraviolet radiation, which is also managed by the Systems Monitoring Program. The system walkdown encompasses all or part of the total accessible system, such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.4 Residual Heat Removal System – Summary of Aging Management Evaluation – Table 3.2.2.4

The staff reviewed LRA Table 3.2.2.4, which summarizes the results of AMR evaluations for the residual heat removal (RHR) system component groups.

In LRA Table 3.2.2.4, the applicant identified no aging effects in RHR system component groups made of aluminum exposed to inside air (external), carbon and low-alloy steel piping/fittings exposed to inside air (external), and copper-alloy and stainless steel fittings carrying air/gas. These environment conditions are not identified in the GALL Report for these components and materials. On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In LRA Table 3.2.2.4, the applicant identified that the loss of material due to general, crevice, pitting and galvanic corrosion in carbon/low-alloy steel heat exchangers, piping, fittings, and other components, cast iron alloy pumps, copper-alloy, and aluminum alloy fitting, and stainless steel piping, fittings, and other components in treated water are managed by the Chemistry Control Program and One-Time Inspection Program. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on BWRVIP-79 to prevent loss of material from general, pitting, crevice or galvanic corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program needs to be performed to ensure that corrosion is not occurring. The one-time inspection of selected components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and the component's intended function will be maintained during the period of extended operation.

In components made from cast iron and copper alloy, selective leaching takes place when these components are exposed to raw water, corrosion-inhibited treated water, oxygenated and de-oxygenated treated water, or are buried underground. In LRA Table 3.2.2.4, the applicant identified the Selective Leaching of Materials Program to manage loss of material due to selective leaching in cast iron heat exchangers and pumps and copper-alloy fittings exposed to raw water or treated water. The applicant's selective leaching program relies on visual inspections and hardness measurements on selected components susceptible to selective leaching. On the basis of industry operating experience with this material and environment, the staff found this acceptable.

Carbon and low-alloy steel components and cast iron/cast iron alloy heat exchangers and pumps' external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. The system walkdown encompasses all or part of the total accessible system such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

In LRA Table 3.2.2.4, heat exchanger components made of carbon/low-alloy steel, cast iron alloys and stainless steel exposed to raw water are susceptible to loss of material due to biofouling, MIC, crevice, galvanic, general, and pitting corrosion as well as fouling product buildup due to biological. The applicant credited the Open-Cycle Cooling Water System Program to manage this aging effect. This AMP, in accordance with the guidelines of GL 89-13, includes managing aging effects by condition monitoring (system and component testing, visual inspections, and NDE testing), and by preventive actions (biocide treatment and filtering to prevent loss of material due to MIC, biofouling, flow blockage and reduction of heat transfer due to biological and particulate fouling). The staff found this acceptable.

Carbon and low-alloy steel and cast iron/cast iron alloy fittings exposed to air/gas are susceptible to loss of material due to general corrosion. In LRA Table 3.2.2.4, the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.5 Core Spray System – Summary of Aging Management Evaluation – Table 3.2.2.5

The staff reviewed LRA Table 3.2.2.5, which summarizes the results of AMR evaluations for the core spray system component groups.

In LRA Table 3.2.2.5, the applicant identified no aging effects in core spray system component groups made of aluminum exposed to inside air (external); carbon and low-alloy steel piping/fittings exposed to inside air (external); and stainless steel fittings carrying air/gas or exposed to inside air. These environment conditions are not identified in the GALL Report for these components and materials. On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group. Therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

In LRA Table 3.2.2.5, the applicant identified that the loss of material due to general, crevice, pitting and galvanic corrosion in carbon/low-alloy steel heat exchangers, piping, fittings, and various other components, cast iron alloy pumps, and stainless steel piping, fittings, and valves in treated water are managed by the Chemistry Control Program and One-Time Inspection Program. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on BWRVIP-79 to prevent loss of material from general, pitting, crevice or galvanic corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause corrosion; therefore, verification of the effectiveness of the Chemistry Control Program needs to be performed to ensure that corrosion is not occurring. The one-time inspection of selected components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and the component's intended function will be maintained during the period of extended operation.

In components made from cast iron alloys, selective leaching takes place when these components are exposed to corrosion-inhibited treated water, oxygenated and de-oxygenated treated water. In LRA Table 3.2.2.5, the applicant identified Selective Leaching of Materials Program to manage loss of material due to selective leaching in cast iron heat exchangers and pumps exposed to treated water. The applicant's selective leaching program relies on visual inspections and hardness measurements on selected components susceptible to selective leaching. On the basis of industry operating experience with this material and environment, the staff found this acceptable.

Carbon/low-alloy steel components and cast iron/cast iron alloy pumps external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. The system walkdown encompasses all or part of the total accessible system, such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

Carbon/low-alloy steel and cast iron/cast iron alloy components exposed to air/gas are susceptible to loss of material due to general corrosion. In LRA Table 3.2.2.5, the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.6 Containment Inerting System – Summary of Aging Management Evaluation – Table 3.2.2.6

The staff reviewed LRA Table 3.2.2.6, which summarizes the results of AMR evaluations for the containment inerting system component groups.

In LRA Table 3.2.2.6, the applicant identified no aging effects in containment inerting system component groups made of aluminum, carbon and low-alloy steel, copper alloys, nickel alloys, and stainless steel carrying air/gas or exposed to inside air. These environment conditions are not identified in the GALL Report for these components and materials. On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group; therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

Carbon/low-alloy steel and cast iron/cast iron alloy components exposed to air/gas are susceptible to loss of material due to general corrosion. In LRA Table 3.2.2.6, the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Repot for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.7 Containment Atmosphere Dilution System – Summary of Aging Management Evaluation – Table 3.2.2.7

The staff reviewed LRA Table 3.2.2.7, which summarizes the results of AMR evaluations for the containment atmosphere dilution system component groups.

In LRA Table 3.2.2.7, the applicant identified no aging effects in containment inerting system component groups made of aluminum, cast iron alloys, copper alloys, and stainless steel carrying air/gas or exposed to inside air. These environment conditions are not identified in the GALL Report for these components and materials. On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments being referred to are typical of ambient air (e.g., under a shelter, indoors, or air-conditioned enclosure or room). Significant corrosion requires an electrolytic environment, and a simultaneous presence of oxygen and moisture. Without the presence of an aggressive environment, these components experience insignificant amounts of corrosion, and no aging effects are applicable to this component/commodity group; therefore, the staff concluded that there are no applicable aging effects for these material and environment combinations.

Carbon/low-alloy steel and cast iron alloy components exposed to air/gas are susceptible to loss of material due to general corrosion. In LRA Table 3.2.2.7, the applicant credited the One-Time Inspection Program to manage loss of material in these components. This aging effect is not in the GALL Report for this component, material, and environment combination. The one-time inspection provides the opportunity to visually inspect the internal surfaces of components during preventive and corrective maintenance activities. The staff found the One-Time Inspection Program acceptable for managing the aging effect of loss of material.

Carbon/low-alloy steel and cast iron alloy components' external surfaces exposed to inside air are managed by the Systems Monitoring Program against any loss of material due to general corrosion. The system walkdown encompasses all or part of the total accessible system such that the entire system is covered over time. The walkdown is a detailed look at system parameters, material condition, operation, configuration, degraded components, outstanding work activities, and design changes. The material condition involves no missing, discolored-indicating-a-potential-leak, or damaged insulation. The staff found that the Systems Monitoring Program would be able to detect any corrosion on the external surfaces of these components.

In LRA Table 3.2.2.7, piping and fittings made of stainless steel buried in soil are susceptible to loss of material due to MIC, crevice, general, and pitting corrosion as well as cracking due to SCC. The applicant credited the Buried Piping and Tanks Inspection Program to manage this aging effect. During the GALL consistency audit the staff requested the applicant to describe how this AMP would detect cracking in buried piping, if this is an applicable aging effect. By letter dated October 8, 2004, the applicant submitted its formal response to the staff's audit question, stating that, in Table 3.2.2.7, line items 12 and 22 identify cracking for buried stainless steel piping and fittings and should be deleted. This line's temperature is less than 140 °F and, therefore, is not subject to stress corrosion cracking. This is the only place in the LRA where the buried tank and piping inspection program was credited for detecting cracking. Therefore, the buried tank and piping inspection program does not detect cracking. The staff found the above explanation acceptable.

The buried tank and piping inspection AMP involves preventive measures to mitigate corrosion (external coatings and wrappings applied in accordance with standard industry practices) and condition monitoring to manage the effects of corrosion. Buried piping is inspected when excavated for any reason, typically for maintenance. The inspections are performed as part of the 10 CFR 50.65, "Maintenance Rule Program." The inspections provide for determination of degradation due to the loss of, or damage to, the protective coatings and wraps used for corrosion control on buried pipe external surfaces. The inspections also include connections and joints for signs of separation, environmental degradation, leakage, and for appreciable settlement between piping segments. The staff found this inspection program acceptable for managing the aging effect of loss of material.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Conclusion. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving MEAP combinations that are not evaluated in the GALL Report. The staff found that the applicant demonstrated that the effects of aging will be adequately managed 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).

3.2.3 Conclusion

The staff concluded that the applicant had provided sufficient information to demonstrate that the effects of aging for the of the ESF systems components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) 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 reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the ESF systems, as required by 10 CFR 54.21(d).

3.3 <u>Aging Management of Auxiliary Systems</u>

This section of the SER documents the staff's review of the applicant's AMR results for the auxiliary systems components and component groups associated with the following systems:

- auxiliary boiler
- fuel oil
- residual heat removal service water
- raw cooling water
- raw service water
- high pressure fire protection
- potable water
- ventilation
- heating, ventilation, and air conditioning (HVAC)
- control air
- service air
- CO_2
- station drainage
- sampling and water quality
- building heat
- raw water chemical treatment
- demineralizer backwash air
- standby liquid control
- off-gas
- emergency equipment cooling water
- reactor water cleanup
- reactor building closed cooling water
- reactor core isolation cooling
- auxiliary decay heat removal
- radioactive waste treatment
- fuel pool cooling and cleanup
- fuel handling and storage
- diesel generator
- control rod drive (CRD)
- diesel generator starting air
- radiation monitoring
- neutron monitoring
- traversing in-core probe
- cranes

3.3.1 Summary of Technical Information in the Application

In LRA Section 3.3, the applicant provided AMR results for components. In LRA Table 3.3.1, "Summary of Aging Management Evaluations for Auxiliary Systems Evaluated in Chapter VII of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the auxiliary systems components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.3.2 Staff Evaluation

The staff reviewed LRA Section 3.3 to determine if the applicant had provided sufficient information to demonstrate that the effects of aging for the auxiliary systems components that are within the scope of license renewal and subject to an AMR will be adequately managed 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 performed an onsite audit, during the weeks of June 21 and July 26, 2004, of AMRs to confirm the applicant's claim that certain identified AMRs are consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff's audit evaluation are documented in the audit and review report and are summarized in SER Section 3.3.2.1.

In the onsite audit, the staff also included those selected AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the acceptance criteria in SRP-LR Section 3.3.2.2. The staff's audit evaluations are documented in the audit and review report and are summarized in SER Section 3.3.2.2.

During the staff's onsite audit, the staff also conducted a technical review of the remaining AMRs that are not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects had been identified and whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the audit and review report and are summarized in SER Section 3.3.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.3.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the auxiliary systems components.

Table 3.3-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.3, that are addressed in the GALL Report.

Table 3.3-1 Staff Evaluation for Auxiliary Systems Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in spent fuel pool cooling and cleanup (Item Number 3.3.1.1)	Loss of material due to general, pitting, and crevice corrosion	Chemistry Control Program; One-Time Inspection Program	Chemistry Control Program; One-Time Inspection Program	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.1)
Linings in spent fuel pool cooling and cleanup system; seals and collars in ventilation systems (Item Number 3.3.1.2)	Hardening, cracking and loss of strength due to elastomer degradation; loss of material due to wear	Plant-specific	Systems Monitoring Program	(See Section 3.3.2.2.2)
Components in load handling, chemical and volume control system (PWR), and reactor water cleanup and *shutdown cooling* systems (older BWR) (Item Number 3.3.1.3)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.7, Other Plant-Specific Analyses, and in Section 4.3, Metal Fatigue BFN does not have a chemical and volume control system or a shutdown cooling system
Heat exchangers in reactor water cleanup system (BWR); high pressure pumps in chemical and volume control system (PWR) (Item Number 3.3.1.4)	Crack initiation and growth due to SCC or cracking	Plant-specific	Chemistry Control Program; One-Time Inspection Program	(See Section 3.3.2.2.4)
Components in ventilation systems, diesel fuel oil system, and emergency diesel generator systems; external surfaces of carbon steel components (Item Number 3.3.1.5)	Loss of material due to general, pitting, and crevice corrosion; MIC	Plant-specific	Chemistry Control Program; One-Time Inspection Program	(See Section 3.3.2.2.4)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in reactor coolant pump oil collect system of fire protection (Item Number 3.3.1.6)	Loss of material due to galvanic, general, pitting, and crevice corrosion	One-Time Inspection	N/A	Not applicable BFN does not have an oil collection system for its reactor recirculation pumps
Diesel fuel oil tanks in diesel fuel oil system and emergency diesel generator system (Item Number 3.3.1.7)	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Fuel Oil Chemistry Program; One-Time Inspection Program	Fuel Oil Chemistry Program; One-Time Inspection Program	Consistent with GALL, which recommends further evaluation (See Section 3.3.2.2.7)
Piping, pump casing, and valve body and bonnets in shutdown cooling system (older BWR) (Item Number 3.3.1.8)	Loss of material due to pitting and crevice corrosion	Chemistry Control Program; One-Time Inspection Program	Chemistry Control Program; One-Time Inspection Program	Not applicable BFN is not an older BWR with a shutdown cooling system The shutdown cooling system is performed by the RHR system (See Section 3.3.2.3.3)
Neutron absorbing sheets in spent fuel storage racks (Item Number 3.3.1.10)	Reduction of neutron absorbing capacity and loss of material due to general corrosion (Boral, boron steel)	Plant-specific	Chemistry Control Program	(See Section 3.3.2.2.10)
New fuel rack assembly (Item Number 3.3.1.11)	Loss of material due to general, pitting, and crevice corrosion	Structures Monitoring Program	Structures Monitoring Program	Consistent with GALL, which recommend no further evaluation (See Section 3.3.2.1)
Neutron absorbing sheets in spent fuel storage racks (Item Number 3.3.1.12)	Reduction of neutron absorbing capacity due to Boraflex degradation	Boraflex Monitoring Program	N/A	Not applicable BFN uses Boral as the spent fuel storage rack neutron absorber
Spent fuel storage racks and valves in spent fuel pool cooling and cleanup (Item Number 3.3.1.13)	Crack initiation and growth due to stress corrosion cracking	Chemistry Control Program	Chemistry Control Program	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in or serviced by closed-cycle cooling water system (Item Number 3.3.1.15)	Loss of material due to general, pitting, and crevice corrosion; MIC	Closed-Cycle Cooling Water System	Closed-Cycle Cooling Water System	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Cranes including bridge and trolleys and rail system in load handling system (Item Number 3.3.1.16)	Loss of material due to general corrosion and wear	Overhead Heavy Load and Light Load Handling Systems	Overhead Heavy Load and Light Load Handling Systems	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Components in or serviced by open-cycle cooling water systems (Item Number 3.3.1.17)	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Buried piping and fittings (Item Number 3.3.1.18)	Loss of material due to general, pitting, and crevice corrosion; MIC	Buried Piping and Tanks Surveillance Program; Buried Piping and Tanks Inspection Program	Buried Piping and Tanks Inspection Program	(See Section 3.3.2.2.11)
Components in compressed air system (Item Number 3.3.1.19)	Loss of material due to general and pitting corrosion	Compressed Air Monitoring Program	Compressed Air Monitoring Program	Consistent with GALL, which recommends no further evaluation (See Section 3.3.2.1)
Components (doors and barrier penetration seals) and concrete structures in fire protections (Item Number 3.3.1.20)	Loss of material due to wear; hardening and shrinkage due to weathering	Fire Protection Program	Fire Protection Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.3.2.1)
Components in water-based fire protection (Item Number 3.3.1.21)	Loss of material due to general, pitting, crevice, and galvanic corrosion, MIC, and biofouling	Fire Water System	Fire Water System	Consistent with GALL, which recommends no further evalation (See Section 3.3.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in diesel fire system (Item Number 3.3.1.22)	*Loss of material due to galvanic, general, pitting, and crevice corrosion*	*Fire Protection Program; Fuel Oil Chemistry Program*	*Fire Protection Program; Fuel Oil Chemistry Program*	*Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.3.2.1)*
Tanks in diesel fuel oil system (Item Number 3.3.1.23)	*Loss of material due to general, pitting, and crevice corrosion*	*Above Ground Carbon Steel Tanks Program*	*Above Ground Carbon Steel Tanks Program*	*Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.3.2.1)*
Closure bolting (Item Number 3.3.1.24)	*Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and SCC*	*Bolting Integrity Program*	*Bolting Integrity Program*	*Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.3.2.1)*
Components in contact with sodium pentaborate solution in standby liquid control system (BWR) (Item Number 3.3.1.25)	Crack initiation and growth due to SCC	Chemistry Control Program	Chemistry Control Program	Consistent with GALL, with exceptions, which recommend no further evaluation (See Section 3.3.2.1)
Components in reactor water cleanup system (Item Number 3.3.1.26)	Crack initiation and growth due to SCC and IGSCC	Reactor Water Cleanup System Inspection Program	BWR Reactor Water Cleanup System Program	The NUREG-1801 XI.M25 Reactor Water Cleanup system AMP provides criteria for which inspections are not recommended. Since BFN meets these criteria, inspections will not be conducted (See Section 3.0.3.2.15)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in shutdown cooling system (older BWR) (Item Number 3.3.1.27)	Crack initiation and growth due to SCC	BWR Stress Corrosion Cracking Program; Chemistry Control Program	N/A	Not applicable BFN is not an older BWR with a shutdown cooling system. The shutdown cooling function is performed by the RHR system (See Section 3.3.2.3.3)
Components in shutdown cooling system (older BWR) (Item Number 3.3.1.28)	Loss of material due to pitting and crevice corrosion, and MIC	Closed-Cycle Cooling Water System	N/A	Not applicable BFN is not an older BWR with a shutdown cooling system. The shutdown cooling function is performed by the RHR system (See Section 3.3.2.3.3)
Components (aluminum, bronze, brass, cast iron, cast steel) in open-cycle and closed-cycle cooling water systems, and ultimate heat sink	Loss of material due to selective leaching	Selective Leaching of Materials Program	Selective Leaching of Materials Program	Consistent with GALL, which recommend no further evaluation (See Section 3.3.2.1)
Fire barriers, walls, ceilings, and floors in fire protection	Concrete cracking and spalling due to freeze-thaw, aggressive chemical attack, and reaction with aggregates; loss of material due to corrosion of embedded steel	Fire Protection System; Structures Monitoring System	Fire Protection System; Structures Monitoring System	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.3.2.1)

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.3.2.1, involves the staff's review of the AMR results for components in the auxiliary systems that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.3.2.2, involves the staff's review of the AMR results for components in the auxiliary systems that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.3.2.3, involves the staff's review of the AMR results for components in the auxiliary systems that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of

AMPs that are credited to manage or monitor aging effects of the auxiliary systems components is documented in SER Section 3.0.3.

3.3.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Not Recommended

Summary of Technical Information in the Application. In LRA Section 3.3.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the auxiliary systems components:

- Bolting Integrity Program (B.2.1.16)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)
- Buried Piping and Tanks Inspection Program (B.2.1.25)
- Fuel Oil Chemistry Program (B.2.1.27)
- Chemistry Control Program (B.2.1.5)
- Open-Cycle Cooling Water System Program (B.2.1.17)
- Closed-Cycle Cooling Water System Program (B.2.1.18)
- Fire Water System Program (B.2.1.24)
- Fire Protection Program (B.2.1.23)
- Compressed Air Monitoring Program (B.2.1.21)
- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program (B.2.1.4)
- BWR Stress Corrosion Cracking Program (B.2.1.10)
- BWR Reactor Water Cleanup System Program (B.2.1.22)
- Flow-accelerated Corrosion Program (B.2.1.15)
- Inspection of Overhead Heavy Load and Light Load Handling Systems Program (B.2.1.20)
- Diesel Starting Air Program (B.2.1.41)

Staff Evaluation. In LRA Tables 3.3.2-1 through 3.3.2-34, the applicant provided a summary of AMRs for the auxiliary systems components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated that the AMR was consistent with the GALL Report.

Note A indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated that the component for the AMR line item is different from but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated that the component for the AMR line item is different from but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicated that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the BFN audit and review report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

The staff conducted an audit and review of the information provided in the LRA, as documented in the BFN audit and review report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs.

The staff reviewed the LRA to confirm that the applicant had (1) provided a brief description of the system, components, materials, and environment, (2) stated that the applicable aging effects were reviewed and evaluated in the GALL Report, and (3) identified those aging effects for the auxiliary systems components that are subject to an AMR. On the basis of its audit and review, the staff determined that, for AMRs not requiring further evaluation, as identified in LRA Table 3.3.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concluded that the AMR results that the applicant claimed to be consistent with the GALL Report are, in fact, consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR54.21(a)(3).

3.3.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.3.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the auxiliary systems. The applicant provided information concerning how it will manage the following aging effects:

- loss of material due to general, pitting, and crevice corrosion
- hardening and cracking or loss of strength due to elastomer degradation or loss of material due to wear
- cumulative fatigue damage
- crack initiation and growth due to cracking or stress corrosion cracking
- loss of material due to general, microbiologically influenced, pitting, and crevice corrosion
- loss of material due to general, galvanic, pitting, and crevice corrosion
- loss of material due to general, pitting, crevice, and microbiologically influenced corrosion and biofouling
- quality assurance for aging management of non-safety-related components
- cracking initiation and growth due to stress corrosion cracking and cyclic loading
- reduction of neutron-absorbing capacity and loss of material due to general corrosion
- loss of material due to general, pitting, crevice, and microbiologically influenced corrosion

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria in SRP-LR Section 3.3.2.2. Details of the staff's audit are documented in the staff's BFN audit and review report. The staff's evaluation of the aging effects is discussed in the following sections.

3.3.2.2.1 Loss of Material due to General, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.1 against the criteria in SRP-LR 3.3.2.2.1.

In LRA Section 3.3.2.2.1, the applicant addressed the further evaluation of programs to manage loss of material in components of the spent fuel pool cooling and cleanup system.

SRP-LR Section 3.3.2.2.1 states that loss of material due to general, pitting, and crevice corrosion could occur in the channel head and access cover, tubes, and tubesheets of the heat exchanger in the spent fuel pool cooling and cleanup system. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on EPRI guidelines of TR-105714 for primary water chemistry and TR-102134 for secondary water chemistry to manage the effects of loss of material from general, pitting or crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause general, pitting, or crevice corrosion. Therefore, verification of the effectiveness of the chemistry control program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material from general, pitting, and crevice corrosion to verify the effectiveness of the Chemistry Control Program. A one-time inspection of select components at susceptible locations is an acceptable method for ensuring that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation. No loss of material aging effects are observed for stainless steel components exposed to air.

Further, SRP-LR Section 3.3.2.2.1 states that loss of material due to pitting and crevice corrosion could occur in the filter housing, valve bodies, and nozzles of the ion exchanger in the spent fuel pool cooling and cleanup system. The Chemistry Control Program relies on monitoring and control of reactor water chemistry based on EPRI guidelines of TR-105714 for primary water chemistry and TR-102134 for secondary water chemistry to manage the effects of loss of material from pitting or crevice corrosion. However, high concentrations of impurities at crevices and locations of stagnant flow conditions could cause pitting, or crevice corrosion. Therefore, verification of the effectiveness of the Chemistry Control Program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material from pitting and crevice corrosion to verify the effectiveness of the Chemistry Control Program. A one-time inspection of select components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

The applicant stated that the portion of the fuel pool cooling and cleanup (FPC) system that contains components requiring an AMR includes the water filled piping within the reactor building, and the applicant credited the Chemistry Control Program and One-Time Inspection Program to manage loss of material. The Chemistry Control Program is credited with managing loss of material for stainless steel components in this portion of the spent fuel pool cooling and cleanup system that are exposed to treated water. The One-Time Inspection Program, which addresses the verification program recommendation in the GALL Report, provides for the inspection of systems to verify that AMPs are effective and that aging effects are not occurring. This is consistent with the GALL Report and acceptable to the staff.

3.3.2.2.2 Hardening and Cracking or Loss of Strength due to Elastomer Degradation or Loss of Material due to Wear

The staff reviewed LRA Section 3.3.2.2.2 against the criteria in SRP-LR 3.3.2.2.2.

In LRA Section 3.3.2.2.2, the applicant addressed the further evaluation of programs to manage the potential for degradation of elastomers in collars and seals in spent fuel cooling systems and ventilation systems.

SRP-LR Section 3.3.2.2.2 states that hardening and cracking due to elastomer degradation could occur in elastomer linings of the filter, valve, and ion exchangers in spent fuel pool cooling and cleanup systems. Hardening and loss of strength due to elastomer degradation could occur in the collars and seals of the duct and in the elastomer seals of the filters in the control room area, auxiliary and radwaste area, and primary containment heating ventilation systems and in the collars and seals of the duct in the diesel generator building ventilation system. Loss of material due to wear could occur in the collars and seals of the duct in the ventilation systems. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

In LRA Section 3.3.2.2.2, the applicant stated that elastomers are not used in components subject to an AMR in the spent fuel cooling and cleanup system. The applicant also stated that for the ventilation systems, hardening and loss of strength due to elastomer degradation is dependent on environmental conditions. The applicant also stated that loss of material due to wear of elastomer components is managed by the systems monitoring program if the environmental threshold is exceeded. The staff found this acceptable.

The staff noted that LRA Table 3.3.2.28 identifies elastomer degradation due to thermal exposure as an AERM for flexible connectors in the diesel generator ventilation system having an internal environment of air/gas. The applicant credited the One-Time Inspection Program to manage this aging effect and claimed consistency with GALL Report, Item VII.F4.1-b, referencing Table 3.2.1, Item 3.3.1.2. However, Table 3.2.1, Item 3.3.1.2 refers to the further evaluation in LRA Section 3.3.2.2.2, which states that the Systems Monitoring Program will be used to manage hardening and loss of strength of elastomers in ventilation systems. The staff during the onsite audit requested the applicant to explain why the One-Time Inspection Program was credited for managing elastomer aging for flexible connectors in the diesel generator ventilation system. In its formal response, by letter dated October 8, 2004, the applicant stated that the One-Time Inspection Program is credited for the inspection of elastomers where the degradation mechanism may be internal. The Systems Monitoring Program is credited for the inspection of elastomers where the degradation mechanism may be external. The applicant stated that LRA Section 3.3.2.2.2 should include a discussion of the One-Time Inspection Program for internal surfaces of elastomers. If degradation is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program. The staff found this acceptable.

3.3.2.2.3 Cumulative Fatigue Damage

In LRA Section 3.3.2.2.3, the applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4 documents the staff's review of the applicant's evaluation of this TLAA.

3.3.2.2.4 Crack Initiation and Growth due to Cracking or Stress Corrosion Cracking

The staff reviewed LRA Section 3.3.2.2.4 against the criteria in SRP-LR 3.3.2.2.4.

In LRA Section 3.3.2.2.4, the applicant addressed the further evaluation of programs to manage the potential for cracking in the regenerative and non-regenerative heat exchanger components in the reactor water cleanup system.

SRP-LR Section 3.3.2.2.4 addresses crack initiation and growth due to SCC in the regenerative and non-regenerative heat exchanger components in the reactor water cleanup system. The GALL Report recommends further evaluation to ensure that these aging effects are managed adequately.

The applicant stated that it uses the Chemistry Control Program and the One-Time Inspection Program to manage cracking and SCC of these stainless steel components. In the ESF section of the GALL Report, Volume 2, Item V.D2.1-c, the management of stainless steel components performing a pressure boundary function is addressed by using the Chemistry Control Program. Therefore, the applicant's use of the Chemistry Control Program to manage crack initiation and growth due to SCC is consistent with the GALL Report and, therefore, is acceptable to the staff.

3.3.2.2.5 Loss of Material due to General, Microbiologically Influenced, Pitting, and Crevice Corrosion

The staff reviewed LRA Section 3.3.2.2.5 against the criteria in SRP-LR 3.3.2.2.5.

In LRA Section 3.3.2.2.5, the applicant addressed the further evaluation of programs to manage the loss of material from corrosion that could occur on internal and external surfaces of components exposed to air and the associated range of atmospheric conditions.

SRP-LR Section 3.3.2.2.5 states that loss of material due to general, pitting, and crevice corrosion could occur in the piping and filter housing and supports in the control room area; the auxiliary and radwaste area; the primary containment heating and ventilation systems; the piping of the diesel generator building ventilation system; the above ground piping and fittings, valves, and pumps in the diesel fuel oil system and in the diesel engine starting air, combustion air intake, and combustion air exhaust subsystems in the EDG system. Loss of material due to general, pitting, crevice, and MIC could occur in the duct fittings, access doors, and closure bolts, equipment frames and housing of the duct. Loss of materials due to pitting and crevice corrosion could occur in the heating/cooling coils of the air handler heating/cooling. Loss of material due to general corrosion could occur on the external surfaces of all carbon steel SCs, including bolting exposed to operating temperatures less than 212°F in the ventilation systems. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

The applicant credited the One-Time Inspection Program for managing loss of material due to corrosion of carbon and low-alloy steel, cast iron/cast iron alloy, and copper alloy components in the off-gas, heating, ventilation, and air conditioning, diesel generator, reactor core isolation cooling, raw cooling water, diesel generator starting air, ventilation, standby liquid control, and demineralizer backwash air systems with internal surfaces exposed to air/gas. The staff found this acceptable.

The applicant credited the Systems Monitoring Program for managing loss of material due to corrosion of carbon and low-alloy steel components in the auxiliary boiler, fuel oil, RHRSW, raw cooling water, raw service water, high pressure fire protection, potable water ventilation, HVAC, control air, service air, CO_2, station drainage, sampling and water quality, building heat, raw water chemical treatment, demineralizer backwash air, standby liquid control, off-gas, emergency equipment cooling water, reactor water cleanup, reactor building closed cooling water, reactor core isolation cooling, radioactive waste treatment, fuel pool cooling and cleanup, diesel generator, CRD, diesel generator starting air, and radiation monitoring systems with external surfaces exposed to air. The staff found this acceptable.

The applicant credited the Diesel Starting Air Program for managing loss of material due to corrosion of carbon and low-alloy steel components in the diesel generator starting air system with internal surfaces exposed to air/gas. The staff found this acceptable.

The staff noted that LRA Table 3.3.2.28 identifies loss of material due to crevice, general, and pitting corrosion as an AERM for carbon and low-alloy steel components in a treated water environment. LRA Table 3.2.1, Item 3.3.1.5 is referenced and consistency with the GALL Report is noted. The Closed-Cycle Cooling Water Program is credited for managing this aging effect. However, LRA Table 3.2.1, Item 3.3.1.5 references the further evaluation in 3.3.2.2.5, which pertains to components in an air environment, and does not include the Closed-Cycle Cooling Water Program as one of the programs to manage aging. The staff inquired as to why LRA Table 3.2.1, Item 3.3.1.5 was referenced for these components. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Table 3.3.2.28 for the diesel generator system has six line items with a treated water environment that match the GALL Report. The correct GALL Report, Volume 1, Table 1 reference for the items that match the GALL Report is Item 3.3.1.15. Five of the LRA Table 3.3.2.28 treated water line items correctly reference 3.3.1.15; one incorrectly references 3.3.1.5. The reference to 3.3.1.5 should be 3.3.1.15. The staff reviewed this response and concluded that it is acceptable.

3.3.2.2.6 Loss of Material due to General, Galvanic, Pitting, and Crevice Corrosion

In LRA Section 3.3.2.2, the applicant addressed the further evaluation of programs to manage loss of material in the reactor coolant pump oil collection system to verify the effectiveness of the Fire Protection Program. The applicant stated that this aging effect is not applicable to BFN since the BFN design does not include a recirculation pump oil collection system. The staff concluded that this is acceptable since the BFN design does not include a reactor coolant pump oil collection system.

3.3.2.2.7 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion and Biofouling

The staff reviewed LRA Section 3.3.2.2.7 against the criteria in SRP-LR 3.3.2.2.7.

In LRA Section 3.3.2.2.7, the applicant addressed the further evaluation of programs to manage loss of material in the diesel fuel oil system to verify the effectiveness of the diesel fuel monitoring program.

SRP-LR Section 3.3.2.2.7 states that loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling could occur in the internal surface of tanks in the diesel fuel oil system and due to general, pitting, and crevice corrosion and MIC in the tanks of the diesel fuel oil system in the EDG system. The existing AMP relies on the Fuel Oil Chemistry Program for monitoring and control of fuel oil contamination in accordance with the guidelines of ASTM Standards D4057, D1796, D2709 and D2276 to manage loss of material due to corrosion or biofouling. Corrosion or biofouling may occur at locations where contaminants accumulate. Verification of the effectiveness of the chemistry control program should be performed to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage corrosion/biofouling to verify the effectiveness of the program. A one-time inspection of selected components at susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the component's intended function will be maintained during the period of extended operation.

In LRA Section 3.3.2.2.7, the applicant stated that it uses the Fuel Oil Chemistry Program to manage loss of material for the diesel fuel oil system. In addition, the applicant will use the One-Time Inspection Program to verify the effectiveness of the fuel oil chemistry program. The inspection will ensure that corrosion is not occurring at locations where contaminants accumulate. The One-Time Inspection Program addresses the one-time inspection recommendation in the GALL Report.

The staff reviewed the Fuel Oil Chemistry Program and found that the program will adequately manage the effects of aging so that the intended functions will be maintained. The staff also reviewed the One-Time Inspection Program, which will be used to verify the effectiveness of the Fuel Oil Chemistry Program.

3.3.2.2.8 Quality Assurance for Aging Management of Non-Safety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's quality assurance program.

3.3.2.2.9 Cracking Initiation and Growth due to Stress Corrosion Cracking and Cyclic Loading

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.3.2.2.10 Reduction of Neutron-Absorbing Capacity and Loss of Material due to General Corrosion

The staff reviewed LRA Section 3.3.2.2.10 against the criteria in SRP-LR 3.3.2.2.10.

In LRA Section 3.3.2.2.10, the applicant addressed the further evaluation of programs to manage reduction of neutron-absorbing capacity and loss of material due to general corrosion, which could occur in the neutron absorbing sheets of the spent fuel storage rack in the spent fuel storage.

SRP-LR Section 3.3.2.2.10 states that reduction of neutron-absorbing capacity and loss of material due to general corrosion could occur in the neutron-absorbing sheets of the spent fuel storage rack in the spent fuel storage. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

The applicant stated that boral is used as a neutron absorbing material in the spent fuel pools. Reduction of neutron absorbing capacity and loss of material due to general corrosion could occur in the boral neutron absorbing material in spent fuel storage racks. The Chemistry Control Program manages general corrosion. An inspection of boral coupon test specimens was performed that confirmed no significant aging degradation had occurred and the neutron absorbing capability of the boral had not been reduced. Reduction of neutron absorbing capacity and loss of material due to general corrosion will be managed by the Chemistry Control Program.

The staff reviewed the Chemistry Control Program and found that the program will adequately manage the effects of aging so that the intended functions will be maintained.

3.3.2.2.11 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

The staff reviewed LRA Section 3.3.2.2.11 against the criteria in SRP-LR 3.3.2.2.11.

In LRA Section 3.3.2.2.11, the applicant addressed the further evaluation of programs to manage the potential for loss of material in buried piping of the service water and diesel fuel oil systems.

SRP-LR Section 3.3.2.2.11 states that loss of material due to general, pitting, and crevice corrosion and MIC could occur in the underground piping and fittings in the OCCW system and in the diesel fuel oil system. The buried piping and tanks inspection program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general, pitting, and crevice corrosion and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

The applicant credited the Buried Piping and Tanks Inspection Program for managing loss of material for buried components of the service water and diesel fuel oil systems. This is consistent with GALL AMP XI.M34, "Buried Piping Inspection." The staff reviewed the applicant's operating history and found that the frequency of pipe excavation was sufficient to manage the effects of loss of material. The staff reviewed the Buried Piping Inspection Program and concluded that it is acceptable.

3.3.2.2.12 Evaluation of Auxiliary Systems AMRs That Reference Further Evaluations Not Included Under Auxiliary Sysyems

In the AMR for components in the auxiliary systems, the applicant referenced several further evaluations that are included under systems other than the auxiliary systems. These further evaluations were referenced based on applicability to the material, environment, and aging effect identified for components in the auxiliary systems. The staff reviewed these further evaluations for applicability to the auxiliary systems; the assessment is documented in the following subsections.

Crack Initiation and Growth due to SCC, IGSCC, and Thermal and Mechanical Loading. In LRA Section 3.1.2.2.4, the applicant addressed the further evaluation of programs to manage crack *initiation and growth due to thermal and mechanical loading or stress corrosion cracking* of components in the reactor coolant system. This aging effect is referenced in LRA Table 3.2.1, Item 3.1.1.7, which the applicant referenced in the auxiliary systems AMRs for components in the sampling and water quality, standby liquid control, reactor water cleanup, reactor core isolation cooling, and neutron monitoring systems.

The staff noted that the LRA identifies crack initiation/growth due to cyclic loading as an AERM for various mechanical components in the sampling and water quality, standby liquid control, reactor water cleanup, reactor core isolation cooling, and neutron monitoring systems. The ASME ISI Program and One-Time Inspection Program are credited to manage this aging effect. The staff noted similar entries in the AMRs for the ESF systems and the reactor coolant system. The staff inquired as to why the Chemistry Control Program had been not included to manage this aging effect for these components since the Chemistry Control Program is included in the further evaluation in LRA Section 3.1.2.2.4. The applicant's response and the staff's evaluation are addressed in SER Section 3.1.2.2.4.

Loss of Material due to General Corrosion. In LRA Section 3.2.2.2.2, the applicant addressed the further evaluation of programs to manage loss of material due to general corrosion for components in the ESF systems. This aging effect is referenced in LRA Table 3.2.1, Items 3.2.1.2, 3.2.1.3, and 3.2.1.10, which the applicant referenced in the auxiliary systems AMRs for components in the auxiliary boiler, raw service water, potable water, service air, station drainage, sampling and water quality, building heat, demineralizer backwash air, off-gas, reactor core isolation cooling, radioactive waste treatment, CRD, and radiation monitoring systems. The staff reviewed the applicant's further evaluation for this aging effect in SER Section 3.2.2.2.

The staff noted that the LRA identifies loss of material due to general, crevice, and pitting corrosion as an AERM for mechanical components in a treated water environment in the radioactive waste treatment system (LRA Table 3.3.2.25). LRA Table 3.2.1, Items 3.2.1.3 and 3.2.1.5 are referenced and consistency with the GALL Report is noted. The One-Time Inspection Program is credited for managing this aging effect; however, the further evaluation in the LRA Section 3.2.2.2.2 identifies the Chemistry Control Program for managing the effects of corrosion for components in a treated water environment. During the onsite audit, the staff inquired as to the technical basis for using the One-Time Inspection Program alone to manage aging due to corrosion for components in a treated water environment, instead of the Chemistry Control program. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the treated water in the radioactive waste treatment system is waste that was generated from systems that contain chemistry control treated water; however, once this water becomes a waste steam, the chemistry can no longer be controlled. Since the portions of the system exposed to treated water have their water source from chemistry control systems, the potential for corrosion is low. The One-Time Inspection Program will verify this by performing a sampling inspection. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff reviewed the applicant's response and concluded that it is acceptable since the water in the radioactive waste treatment system is waste that was generated from systems that contain chemistry control treated water. Once the treated water becomes a waste stream the chemistry can no longer be controlled, which is why the Chemistry Control Program is not credited for this aging effect. The potential for corrosion is low for these components and the One-Time Inspection Program will be performed to verify that corrosion is not occurring.

The staff noted that LRA Tables 3.3.2.3, 3.3.2.5, 3.3.2.14, 3.3.2.21, and 3.3.2.25 identify loss of material due to biofouling, MIC, crevice corrosion, general corrosion, and pitting corrosion as an AERM for stainless steel components in a raw water environment. LRA Table 3.2.1, Items 3.2.1.3, 3.2.1.5, and 3.2.1.6 are referenced and consistency with the GALL Report is noted. LRA Table 3.2.1, Items 3.2.1.3, 3.2.1.5 and 3.2.1.6 reference further evaluations in LRA Sections 3.2.2.2.2. 3.2.2.2.3, and 3.2.2.2.4, respectively. However, LRA Sections 3.2.2.2.2 and 3.2.2.2.3 pertain to components in treated water, for which the Chemistry Control and One-Time Inspection Programs are identified to manage this aging effect. Only LRA Section 3.2.2.2.4 pertains to components in raw water. The staff asked why LRA Table 3.2.1, Items 3.2.1.3 and 3.2.1.5 are referenced for these components. The staff also inquired as to the technical basis for using the One-Time Inspection Program to manage aging due to MIC for the components in Table 3.3.2.25 instead of the Open-Cycle Cooling Water Program. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Sections 3.2.2.2.2 and 3.2.2.2.3 only address treated water environments and should include a discussion of the Open-Cycle Cooling Water Program for raw water systems.

The staff found this acceptable, because the applicant indicated that LRA Sections 3.2.2.2.2 and 3.2.2.2.3 should also include raw water environments and credited the Open-Cycle Cooling Water Program for raw water systems. With these additions, the applicant's AMR results will be consistent with the GALL Report.

Loss of Material due to Pitting and Crevice Corrosion. In LRA Section 3.2.2.2.3, the applicant addressed the further evaluation of programs to manage the loss of material due to pitting and crevice corrosion for components in the engineered safety feature systems. This aging effect is referenced in LRA Table 3.2.1, Items 3.2.1.4 and 3.2.1.5, which the applicant referenced in the auxiliary systems AMRs for components in the raw service water, sampling and water quality, building heat, reactor core isolation cooling, auxiliary decay heat removal, radioactive waste treatment, CRD, and radiation monitoring systems. The staff reviewed the applicant's further evaluation for this aging effect in SER Section 3.2.2.3.

The staff noted that the LRA identified loss of material due to crevice and pitting corrosion as an AERM for mechanical components in a treated water environment in the radiation monitoring system (LRA Table 3.3.2.31). The applicant referenced LRA Table 3.2.1, Item 3.2.1.5 and consistency with the GALL Report is noted. The Closed-Cycle Cooling Water Program is credited for managing this aging effect. However, the further evaluation in LRA Section 3.2.2.2.3 identifies the Chemistry Control Program and One-Time Inspection Program for managing the effects of corrosion for components in a treated water environment. The staff inquired as to the technical basis for using the Closed-Cycle Cooling Water Program alone to manage aging due to corrosion for components in a treated water environment instead of the Chemistry Control Program and One-Time Inspection Program. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the Closed-Cycle Cooling Water Program is consistent with the related GALL Report Closed-Cycle Cooling Water Program (XI.M21). The Closed-Cycle Cooling Water Program provides for prevention and detection of aging effects in plant closed cycle cooling water systems. LRA Section 3.2.2.2.3 only addresses treated water environments and should include a discussion of the Closed-Cycle Cooling Water Program for treated water in closed cooling loops.

The staff found this acceptable because the applicant indicated that LRA Section 3.2.2.2.3 should also include treated water in closed cooling loops and credit the Closed-Cycle Cooling Water Program.

Local Loss of Material due to Microbiologically Influenced Corrosion. In LRA Section 3.2.2.2.4, the applicant addressed the further evaluation of programs to manage the local loss of material due to MIC for components in the engineered safety feature systems. This aging effect is referenced in LRA Table 3.2.1, Item 3.2.1.6, which the applicant referenced in the auxiliary systems AMRs for components in the raw service water, sampling and water quality, radioactive waste treatment, and radiation monitoring systems. The staff reviewed the applicant's further evaluation for this aging effect in SER Section 3.2.2.2.4.

The staff noted that LRA Table 3.3.2.25 identifies loss of material due to MIC as an AERM for components in a raw water environment in the radioactive waste treatment system. LRA Table 3.2.1, Items 3.2.1.3, 3.2.1.5, and 3.2.1.6, are referenced, and consistency with the GALL Report is noted. The One-Time Inspection Program is credited to manage this aging effect. However, Section 3.2.1.6 references the further evaluation in LRA Section 3.2.2.2.4, which identifies the Open-Cycle Cooling Water Program for managing MIC. The staff inquired as to the technical basis for crediting the One-Time Inspection Program for managing aging due to MIC for these components. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the raw water environment identified in the radioactive waste treatment system is waste that was generated from floor and equipment drain sumps and may contain dirty or contaminated water. This waste stream is not subject to the Chemistry Control Program or the Open-Cycle Cooling Water Program. The potential for corrosion in this system would be lower than actual "raw water" systems because a portion of the waste stream would be treated water from chemistry control systems. The applicant determined that inspection in accordance with the One-Time Inspection Program will verify integrity of this system during the period of extended operation. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff reviewed the applicant's response and concluded that it is acceptable since the raw water environment identified in the radioactive waste treatment system is waste that was generated from floor and equipment drain sumps and may contain dirty or contaminated water. The potential for corrosion in this system would be lower than actual raw water systems because a portion of the waste stream would be treated water from chemistry control systems. The One-Time Inspection Program will verify integrity of this system during the period of extended operation.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.3.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.3.2.1 through 3.3.2.34, the staff reviewed additional details of the results of the AMRs for material, environment, AERM, and AMP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Tables 3.3.2.1 through 3.3.2.34, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report, and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

For component type, material, and environment combination that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

During its review, the staff determined that similar AMR line items required clarification for several systems. In several of the auxiliary systems, the LRA states that copper alloy components in an inside air (external) environment experience no AERMs. However, the existence of AERMs depends on the particular alloy and whether there is condensation or pooling on the component. For example, high zinc (>15 percent) alloys in condensation or pooling water may exhibit stress corrosion cracking, selective leaching, or pitting and crevice corrosion. The LRA definition of inside air (external) would support condensation and pooling.

In RAI 3.3.2.1-1, dated October 12, 2004, the staff requested the applicant to clarify how condensation and pooling were considered in the evaluation of potential aging of susceptible alloys. In its response, by letter November 3, 2004, the applicant stated that the copper alloy components exposed to an inside air (external) environment were evaluated individually to determine where condensation could occur (i.e., components containing fluid at a temperature below the dew point of the external environment). The aging effects evaluation then determined the aging effects/mechanisms based on the particular alloys are susceptible and whether condensation or periodic wetting occurred. The applicant provided its guidelines for assessing the particular alloys.

The staff reviewed the applicant's criteria for determining aging effects based on the particular copper alloy and found them acceptable and consistent with industry guidance. The applicant evaluated the components individually and applied acceptable criteria for determining the AERMs of the alloys exposed to condensation or pooling. Therefore, the staff found the applicant's evaluation of copper alloys in inside air to be acceptable.

<u>Aging Management of Bolting in Auxiliary Systems Bolting</u>. The staff reviewed LRA Tables 3.3.2.1 through 34, which relates to the AMR evaluations for bolting in auxiliary systems bolting. The staff was concerned that cracking and loss of preload are not identified as aging effects for bolting managed by the Bolting Integrity Program, including bolting subject to high pressure, high temperature or vibration. The Bolting Integrity Program should provide for bolting preload control for all bolting within scope of license renewal.

The LRA AMR tables credit the Bolting Integrity Program for managing loss of bolting function due to various corrosion mechanisms in auxiliary systems bolting. Loss of preload and cracking are not identified as aging effects for bolting in the AMR tables for auxiliary systems.

GALL AMP XI.M18 specifically credits the Bolting Integrity Program developed and implemented in accordance with commitments made in response to communications on bolting events to provide an effective means of ensuring bolting reliability. The program relies on industry recommendations for a comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure retaining bolting. The program covers all bolting within the scope of license renewal. The GALL Report includes loss of material, cracking and loss of preload as aging effects. Bolting preload control, as delineated in EPRI NP-5769 with exceptions noted in NUREG-1339, is applied to manage loss of preload. NUREG CR-6679 also identifies loss of preload as an aging effect and the draft GALL Report update 2005 includes loss of preload as an aging effect for bolting in ESF, auxiliary and S&PC systems. Further, SRP-LR Section A.1.2.1 states, "However leakage from bolted connections should not be considered abnormal events. Although bolting connections are not supposed to leak, experience has shown that leaks do occur, and the leakage could cause corrosion. Thus, the aging effects from leakage of bolted connections should be evaluated for license renewal."

The Bolting Integrity Program is identified as an existing program that takes exceptions to GALL AMP XI.M18 evaluation elements. The exceptions affect element 1 - scope of the program and possibly element 4 - detection of aging effects. It appears that Element 4 - detection of aging effects - is identified as being affected by the exceptions. The applicant credits ASME Code

Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program for ASME Section XI inspections of Class 1 and Class 2 bolting.

For auxiliary system closure bolting, the staff is concerned that cracking and loss of preload are not entirely addressed by either the ASME Code Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program or Bolting Integrity Program. Although ASME Section XI requires bolt torquing loads to be in accordance with ASME Section III for replacement of Class 1 and 2 bolting, no bolt torquing requirements are specified for Class 3 bolting, NSR bolting or bolting that is reused after being removed for maintenance. ASME Section XI does address examination of Class 1 bolting, but no examination is required for Class 2 bolting smaller than 2 inch and Class 3 bolting regardless of size or NSR bolting. ASME Section XI does provide for inspection during leakage testing, but this inspection may not necessarily detect loss of preload or flange leakage at other times. GALL AMP XI.M18, "Bolting Integrity," does manage cracking and loss of preload in all closure bolting within scope of license renewal. As identified in EPRI NP-5769, preload reduction is caused by a number of factors, including stress relaxation (both at room temperature and elevated temperature), thermal cycling (particularly for gaskets), creep and flow of gasket material during initial compression, vibration and shock, and elastic interactions between separately-tightened bolts. The GALL Report includes high pressure and high temperature systems as being susceptible to crack initiation. Therefore, the applicant should clarify if the bolting integrity AMP is consistent with GALL AMP XI.M18 in regard to managing cracking and loss of preload or explain how these aging effects are managed by other programs or maintenance practices.

By letter dated October 8, 2004, the applicant provided additional information in response to Audit Inspection Question 310 on bolting activities. The applicant stated that, "Structural bolting procurement activities, receipt inspection and installation (torquing), as defined in TVA procedure General Engineering Specification (GES) G-29B-S01, P.S.4.M.4.4, ASME Section III and Non-Section III (including American Institute of Steel Construction (AISC), ANSI B31.1, and ANSI B31.5) bolting material, are considered part of the Bolting Integrity Program and meet the industry recommendations for these activities as delineated in NUREG-1339 and EPRI NP-5769.

By letter dated March 16, 2005, the applicant responded to the clarification request on bolting. For valve closure bolting not within the RCPB, the applicant clarified that stress relaxation is a thermal effect that results in loss of preload. The applicant explained that stress relaxation is a design driven effect that would be detected and corrected early and is not considered an applicable aging effect in non-RCPB valve closure bolting. The applicant stated that installation procedures are in place that specify proper bolting installation practices and bolt torque values. In this letter, the applicant also clarified that non-RCPB bolting is not susceptible to SCC as the yield strength is less than 150 ksi. Further, the applicant explained that crack initiation and growth due to cyclic loading is not considered a license renewal concern due to high cycle fatigue, since it would be discovered and corrected during the current licensing period.

The staff reviewed the applicant's response and agreed that loss of preload in auxiliary system closure bolting should be managed by proper bolting installation practices and torque values supplemented by inspections. The staff also concurred that proper bolting practices and the selection of bolting less than 150 ksi should result in auxiliary system closure bolting not being susceptible to SCC.

However, the staff did not agree that cracking and loss of preload are not aging effects for license renewal, unless the applicant demonstrates that these potential adverse effects will be corrected prior to the period of extended operation. LRA Section B.2.1.16 states that the BWR fleet of plants, including BFN, has experienced bolting degradation issues. Plant-specific and industry operating experience should be reviewed to determine if the applicant's bolting practices are effective in precluding loss of preload and cracking for all auxiliary system closure bolting within the scope of license renewal. For example, despite implementation of bolting practices, recent industry operating experience such as LER 2005-01 for Fermi 2 demonstrates the importance of sufficient bolt torque to prevent major gasket leakage in BWR auxiliary systems such as reactor building closed cooling water (RBCCW). The applicant was requested to review operating experience and submit the results of any self assessments, inspections or maintenance activities to determine if closure bolting in auxiliary systems will be effectively managed for cracking and loss of preload. This information should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the component intended function(s) will be maintained during the period of extended operation. If by a review of operating experience the applicant cannot demonstrate that effective bolting practices are in place to manage cracking and loss of preload in auxiliary system closure bolting, the applicant should commit to a Bolting Integrity Program consistent with the GALL Report or explain how these aging effects are managed by other programs or maintenance practices.

By letter dated June 3, 2005, the applicant provided additional information concerning cracking and loss of preload in auxiliary systems bolting. In this response the applicant included information relevant to their review of operating experience with bolting.

Cracking - The applicant clarified that high yield strength heat-treated alloy steel bolting materials are not specified for flanged connections at BFN. The applicant also clarified that the use of MoS_2 thread lubricant is not allowed by site and engineering procedures. Further the applicant clarified that a review of the operating experience had not identified any instances where mechanical component failure was attributable to stress corrosion cracking of high strength pressure boundary bolting. Thus, the applicant concluded that the aging effect loss of bolting function was not identified at BFN because both the susceptible material and corrosive environment portions of the stress corrosion crack mechanism are not present.

Loss of Preload - The applicant clarified that loss of preload due to stress relaxation (creep) is not an aging effect for standard grade B7 carbon steel bolting used in auxiliary system bolting with temperatures less than 700 °F. The applicant also clarified that BFN has taken actions to address NUREG-1339, "Resolution to Generic Safety Issue 29; Bolting Degradation or Failure in Nuclear Power Plants." These actions include the implementation of good bolting practices in accordance with those referenced in EPRI NP-5769, with the exceptions noted in NUREG-1339, and EPRI TR-104213 to address the potential for joint failure such that it is not a concern for the current or extended operating term. The applicant identified that a review of the BFN operating experience did not identify any instances where the mechanical component failure was attributable to loss of pressure boundary bolting preload. In regard to recent industry experience with joint failures associated with loss of preload identified in Fermi 2 LER 2005-01, the applicant attributed this failure to inadequate gasket compression due to a number of factors including insufficient initial bolt torque. The applicant characterizes this failure as indicative of a design/maintenance problem rather than an aging concern.

The staff reviewed the applicant's response dated March 16, 2005, and found the response to be reasonable and acceptable. The applicant provided additional information to clarify that cracking and loss of preload in bolting are being effectively managed. However, the response did not provide the results of any self assessments, inspections or maintenance activities, and operating experience to determine if closure bolting in auxiliary systems was effectively managed at BFN for cracking and loss of preload. The staff discussed this issue with the applicant in a teleconference, and the verification of this confirmatory item was addressed during the AMP inspection performed on September 2005. The applicant also agreed to include this in the Appendix A Commitment Table. In the inspection report, a letter dated November 3, 2005, the staff concluded that the bolting practices in BFN are functioning adequately. The staff, therefore, concluded that there is reasonable assurance that aging effects, including cracking and loss of preload, for bolting used in auxiliary systems are being and will continue to be effectively managed during the period of extended operation.

No Aging Effect or Aging Management Program Identified. The staff reviewed LRA Tables 3.3.2.1 through 3.3.2.34, which summarized the results of AMR evaluations for the auxiliary systems component groups.

The applicant included entries in these tables for which there are no aging effects or AMPs identified. However, the material/environment combinations for these components do have aging effects identified in other table entries. For example, LRA Table 3.3.2.31, row 14 shows stainless steel fittings in treated water with no aging effect or AMP, while the next row has the same component/material/ environment with loss of material identified as an AERM. The staff inquired as to the purpose of the entries showing no aging effect or AMP. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the reason for the line entries that indicate no aging effects is an attempt to ensure completeness of the GALL Report comparison. For the example given, LRA Table 3.3.2.31, rows 14 and 15 address stainless steel fittings that form a portion of containment isolation. The applicable GALL Report, Volume 2 line item was determined to be V.C.1-b. GALL Report, Volume 2, Item V.C.1-b lists four aging effects; pitting and crevice corrosion; MIC; and biofouling. For a treated water line, the AMR determined that MIC and biofouling did not require management for the period of extended operation. This was documented in the AMR as:

- pitting corrosion – Yes
- crevice corrosion – Yes
- MIC – No
- biofouling – No

The first two aging mechanisms form the basis for LRA Table 3.3.2.31, row 15. The last two are documented in LRA Table 3.3.2.31, row 14 as no aging effect with Note 4 identified. Note 4 states, "Based on system design and operating history, MIC and biofouling are not applicable to the treated water portions of this system." Also, Table 3.3.2.14, row 58 should refer to Notes I, 5, and Table 3.3.2.28; row 56 should refer to Notes I, 2.

The staff found that the applicant's entries showing no aging effect or AMP are acceptable since they are included only to ensure completeness of the GALL Report comparison; and also concurred with the corrections identified for LRA Table 3.3.2.14, row 58 and LRA Table 3.3.2.28, row 56.

The staff reviewed LRA Tables 3.3.2.6, 3.3.2.9, 3.3.2.12, 3.3.2.14, 3.3.2.21, 3.3.2.22, 3.3.2.23, 3.3.2.28, 3.3.2.30, and 3.3.2.31, which summarize the results of AMR evaluations for the high pressure fire protection; heating, ventilation, and air conditioning; CO_2, sampling and water quality; reactor water cleanup; reactor building closed cooling water; reactor core isolation cooling; diesel generator; diesel generator starting air; and radiation monitoring systems component groups, respectively.

The applicant identified glass fittings in environments of air/gas, inside air, treated water, raw water, lubricating oil, and aqueous film-forming foam (AFFF) as having no aging effects requiring management. During the onsite audit, the staff inquired as to the specific applications of these glass fittings and the chemical properties of AFFF with regard to its reactivity with glass. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the following components, which contain glass, are included within the scope of license renewal for BFN:

- *System 26, High Pressure Fire Protection - level gauge*
- System 31, Heating, Ventilation, and Air Conditioning - level gauge
- System 37, Gland Seal Water - level gauge
- System 39, CO_2 - level gauge
- System 43, Sampling and Water Quality - level gauge
- System 64, Containment - level gauge
- System 68, Reactor Recirculation - sight glass
- System 70, Reactor Building Closed Cooling Water - level gauge
- System 82, Diesel Generator - level gauge
- System 86, Diesel Generator Starting Air - sight glass
- System 90, Radiation Monitoring - sight glass, moisture traps, and air filters

In addition, the applicant stated that AFFF contains the following:

- water
- 2-(2-butoxyethoxy) ethanol
- ethylene glycol
- alkyl polyglycoside
- fluoroalkyl surfactant

This mixture of hydrocarbons, surfactants, fluorosurfactants, and water is not reactive with glass.

The staff concluded that the applicant's determination of no aging effect for these glass components for the environments identified is acceptable since the environments identified are not reactive with glass.

3.3.2.3.1 Auxiliary Boiler System – Summary of Aging Management Evaluation – Table 3.3.2.1

The staff reviewed LRA Table 3.3.2.1, which summarizes the results of AMR evaluations for the auxiliary boiler system component groups.

In LRA Table 3.3.2.1, the applicant proposes that fittings, piping, and valves made from carbon and low-alloy steel in an environment of treated water (internal) and subjected to galvanic corrosion will be managed by the One-Time Inspection Program.

The staff reviewed the One-Time Inspection Program and its evaluation is documented in SER Section 3.0.3.1. Galvanic corrosion is typically minimized through standard design practices. Therefore, any galvanic corrosion is expected to be sufficiently slow that the One-Time Inspection Program is appropriate for this aging effect. If there is any significant galvanic corrosion, this AMP will identify the problem and initiate appropriate corrective action. Therefore, the staff found the use of the One-Time Inspection Program to be appropriate for this aging effect.

LRA Section 3.3.2.1, states that valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

In general RAI 3.3.2.1-1 the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

On the basis of its review of the information provided in the LRA and the additional information provided, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the auxiliary boiler system.

<u>Loss of Material Due to Corrosion for Cast Iron and Carbon/Low Alloy Steels in an Air/Gas Environment</u> The applicant identified loss of material due to crevice, general, and pitting corrosion as an AERM for valves constructed of cast iron and cast iron alloy, as well as fittings, piping, traps, and valves constructed of carbon or low-alloy steel in a moist air/gas environment on their internal surface. The One-Time Inspection Program is credited for managing this aging effect. The staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for these material and environment combinations for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the air/gas components in the auxiliary boiler system were exposed to secondary quality water or steam that had been isolated by the layup of the auxiliary boilers. The portions of the system that now contain air/gas are isolated and there is no mechanism for introducing contaminants or additional oxygen. Since the portions of the auxiliary boiler system exposed to air/gas were originally chemistry controlled, the potential for corrosion is low. The One-Time Inspection Program will verify this by performing a sampling inspection. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable. The water to which these components were exposed was chemically treated, and the components are now isolated such that neither contaminants nor additional oxygen will be introduced into the air/gas environment. Therefore, the potential for corrosion of these components is low. The one-time inspection will verify that corrosion is not occurring. If corrosion is detected, additional inspections and corrective actions will be taken.

Loss of Material due to Selective Leaching of Copper Alloy in a Treated Water Environment. The applicant identified loss of material due to selective leaching for components constructed of copper alloy in a treated water environment on their internal surface as an AERM. The One-Time Inspection Program is credited for managing this aging effect. The staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for this material and environment combination for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the One-Time Inspection Program had been identified in error. The correct AMP for this aging effect is the Selective Leaching of Materials Program.

The staff concluded that the applicant's response is acceptable since the Selective Leaching of Materials Program was developed specifically to address loss of material due to selective leaching. The One-Time Inspection Program was incorrectly listed in Table 3.2.2.1 for this component.

3.3.2.3.2 Fuel Oil System – Summary of Aging Management Evaluation – Table 3.3.2.2

The staff reviewed LRA Table 3.3.2.2, which summarizes the results of AMR evaluations for the fuel oil system component groups.

In LRA Table 3.3.2.2, the applicant states that pumps, piping, and fittings made from carbon and low-alloy steel in fuel oil experience no aging effects. Copper alloy in fuel oil is subjected to loss of material due to MIC. The applicant also states that fittings made from copper alloy in inside air experience no aging effects. For flexible hoses made from elastomer - rubber in fuel oil (internal) subjected to elastomer degradation due to oxidation, the applicant proposes that these be managed by the One-Time Inspection Program. Flexible hoses made from elastomer - rubber in inside air may experience elastomer degradation due to ultraviolet radiation, and will be managed by the Systems Monitoring Program.

LRA Section 3.3.2.2 states that components made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. In a general RAI, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

The staff's review of LRA Section 3.3.2.2 identified areas in which additional information was necessary to complete the review of the applicant's results. The applicant responded to the staff's RAI as discussed below.

In RAI 3.3.2.2-2, dated October 12, 2004, the staff noted that numerous line items In LRA Table 3.3.2.2 state that carbon and low-alloy steel components in fuel oil experience no AERMs and require no AMPs. This is not consistent with the GALL Report or with industry experience. Notes associated with these line items indicate that the AERMs identified in the GALL Report for this material/environment combination are not applicable (Note I) for the following reasons: (1) pitting, crevice, general, or galvanic corrosion are not concerns because there is no water collection in these components (Note 5, applied to fittings, piping, pumps, restricting orifice, strainers, and tubing); (2) biofouling is not a concern (Note 7, applied to tanks); or (3) galvanic corrosion is not a concern because there are no galvanic couples in the portions of the system where water could accumulate and provide a conductor (applied to tanks). Adjacent line items in LRA Table 3.3.2.2 for the same material, environment, and GALL reference state that the components are subjected to loss of material due to MIC and credit the Fuel Oil Chemistry Program and the One-Time Inspection Program for aging management. Therefore, the staff requested the applicant to clarify the above AMR and whether the Fuel Oil Chemistry Program and the One-Time Inspection Program are credited for all carbon steel and low-alloy components in the system.

In its response, by letter dated November 3, 2004, the applicant clarified that the AMR line items that state that carbon and low-alloy steel components in fuel oil experience no AERMs are there to indicate that some potential aging mechanisms identified in the GALL Report are not applicable. GALL Report, Volume 2, Section VII.G.8-a, lists the four aging mechanisms as general, galvanic, pitting, and crevice corrosion, while the applicant's AMR determined that the only aging mechanism applicable to these components (where there is no water accumulation) is MIC. MIC forms the basis of the adjacent AMR line item. The applicant also clarified that the Fuel Oil Chemistry Program and the One-Time Inspection Program are credited as aging managements programs for all carbon steel and low-alloy steel components in the fuel oil system with a fuel oil internal environment. The staff concurred with the applicant's assessment that MIC is the predominant aging effect for carbon and low-alloy steel in fuel oil where there is no potential for water accumulation. The staff also noted that the inspections performed on this system will identify the AERMs in the GALL Report, if they are present. Therefore, the staff found that the applicant had identified the appropriate aging effects.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the fuel oil system.

LRA Table 3.3.2.2 identifies the following AMPs for managing the aging effects described above: Fuel Oil Chemistry Program, One-Time Inspection Program, and the Systems Monitoring Program. The staff's detailed reviews of these AMPs are found in SER Sections 3.0.3.2.18, 3.0.3.1.7, and 3.0.3.3.1, respectively.

In RAI 3.3.2.2-1, dated October 12, 2004, the staff stated that LRA Section 3.3.2.2. implies that the one-time inspections will be limited to the system locations where contaminants are expected to accumulate; however, AERMs (particularly MIC) are identified for a larger population of components. Therefore, the staff requested the applicant to clarify the use of the one-time inspections. In its response, by letter November 3, 2004, the applicant stated that the Fuel Oil Chemistry Program and the One-Time Inspection Program are credited as AMPs for all components in the fuel oil system with a fuel oil internal environment where aging effects were identified. These programs are being applied to all components with identified AERMs; therefore, the staff found this acceptable.

For the flexible hoses made of elastomer (rubber) in a fuel oil environment, the LRA credits the One-Time Inspection Program to manage the aging effect of elastomer degradation due to oxidation. The One-Time Inspection Program is typically used to verify that an aging effect is not occurring or when an aging effect is expected to occur slowly, such that the component intended function can be maintained for the extended period of operation. For these same hoses, the LRA credits the Systems Monitoring Program to manage the aging effect of elastomer degradation due to ultraviolet radiation. The Systems Monitoring Program provides for visual inspections of the hoses. The staff found the periodic inspections, combined with the one-time inspection of the hose internal surface, adequate for managing the aging of the flexible hoses. Therefore, the staff found the management of these hoses to be acceptable.

The staff reviewed LRA Table 3.3.2.2, which summarized the results of AMR evaluations for the fuel oil system component groups. The applicant identified no aging effect or AMP for components constructed of cast iron and cast iron alloy, as well as carbon or low-alloy steel in an air/gas environment on their internal surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for these material/environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that components in the fuel oil system are exposed to a fuel oil vapor environment. This fuel oil vapor environment protects the component surfaces and prevents internal corrosion.

The staff concluded that the applicant's determination of no AERMs for components in the fuel oil system in an air/gas environment on the internal surface is acceptable since the components will be exposed to fuel oil vapor, which will protect the surfaces of the components from corrosion.

On the basis of its review of the information provided in the LRA and RAI responses, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the above fuel oil system components. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

<u>No Aging Effect or Aging Management Program Identified</u>. The applicant identified no aging effect or AMP for components constructed of cast iron and cast iron alloy, as well as carbon or low-alloy steel in an air/gas environment on their internal surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for these material/environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that components in the fuel oil system are exposed to a fuel oil vapor environment. This fuel oil vapor environment protects the component surfaces and prevents internal corrosion.

The staff concluded that the applicant's determination of no AERMs for components in the fuel oil system in an air/gas environment on the internal surface is acceptable since the components will be exposed to fuel oil vapor, which will protect the surfaces of the components from corrosion.

3.3.2.3.3 Residual Heat Removal Service Water System – Summary of Aging Management Evaluation – Table 3.3.2.3

The staff reviewed LRA Table 3.3.2.3, which summarizes the results of AMR evaluations for the RHRSW system component groups.

In LRA Table 3.3.2.3, the applicant identifies aging effect for the RHRSW system components within the scope of license renewal and subject to AMR. The AMR lists the components, materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, piping, and valves made from aluminum alloy in an environment of treated water (internal) are subjected to crack initiation and growth due to SCC, and loss of material due to crevice and pitting corrosion, and will be managed by the Chemistry Control Program and the One-Time Inspection Program. Fittings, piping, and valves made from carbon and low-alloy steel in an environment of treated water (internal) are subject to loss of material due to crevice, general, and pitting corrosion. Fittings made from polymer in environments of inside air (external) and treated water (internal) experience no AERMs and require no AMPs.

Through a staff teleconference follow up request dated February 11, 2005, the staff requested the applicant to provide additional clarification regarding the type of elastomer or polymer, its environment, and justification that there are no AERMs for the elastomer or polymer components. In its response, by letter dated March 11, 2005, the applicant clarified that the polymer components in this system are Derlin (acetal) insulating couplings between dissimilar material threaded piping. Based on its review of the material data sheet for Derlin, the staff concluded that the material is rated for continuous service in environmental conditions (e.g., temperature) significantly in excess of the conditions in the RHRSW system. Therefore, the staff concurred with the applicant's evaluation that there are no AERMs for the polymer components in this system.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the RHRSW.

No Aging Effect or Aging Management Program Identified. The applicant identified no aging effect or AMP for components constructed of cast iron and cast iron alloy, as well as carbon or low-alloy steel in an embedded/encased environment on their external surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for these material and environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that no aging effects are identified for embedded/encased components. If excessive corrosion that could prevent the performance of the intended functions during the period of extended operation was detected on the inside surface or outside surface in air environments adjacent to the embedded/encased portions, corrective actions would be taken to restore the component, including the embedded/encased portions, if this was determined to be necessary.

The staff concluded that the applicant's determination of no AERMs for components in the RHRSW system in an embedded/encased environment is acceptable since exposure to a corrosive environment will be limited. Inspections will be performed on adjacent surfaces exposed to an air environment. If corrosion was detected on adjacent surfaces in an air environment, corrective actions would be taken to restore the component, including the embedded/encased portions, if this was determined to be necessary.

3.3.2.3.4 Raw Cooling Water System – Summary of Aging Management Evaluation – Table 3.3.2.4

The staff reviewed LRA Table 3.3.2.4, which summarizes the results of AMR evaluations for the raw cooling water system component groups.

In LRA Table 3.3.2.4, the applicant identifies aging effect for the raw cooling water system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs; expansion joints made from elastomer exposed to inside air (external) and raw water (internal) experience no AERMs and require no AMPs; fittings and piping made from polymer in air/gas (internal) or inside air (external) environments experience no AERMs and require no AMPs.

In the general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

In its response to the staff's informal request February 11, 2005, by letter dated March 11, 2005, the applicant clarified that the elastomer components are fabric reinforced expansion joints (Garlock Style 204) made from chlorobutyl/polyester. The coating cover reduces ultraviolet radiation to negligible levels, the system temperature is low relative to the qualified temperature, and the elastomers are not exposed to significant radiation. Based on the above, the staff concurred with the applicant's conclusion that there are no AERMs for the elastomer components in this system.

With respect to the polymer components, by the letter dated March 11, 2005, the applicant clarified that the polymer components are molded plastic fittings and piping in air/gas and inside air. The applicant stated that once the proper polymer, resistant to the environment, is chosen, there are no AERMs. The applicant further stated that industry guidance does not identify any AERMs for this polymer and environment, but that the components would be included in the Systems Monitoring Program to verify that there is no hardening or loss of material strength due to polymer degradation.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the raw cooling water system.

3.3.2.3.5 Raw Service Water System – Summary of Aging Management Evaluation – Table 3.3.2.5

The staff reviewed LRA Table 3.3.2.5, which summarizes the results of AMR evaluations for the raw service water system component groups.

In LRA Table 3.3.2.4, the applicant identifies the aging effects of the service water system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR line items that do not rely on the GALL Report are as follows: fittings and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

In a general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.1.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the RAI, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.6 High Pressure Fire Protection System – Summary of Aging Management Evaluation – Table 3.3.2.6

The staff reviewed LRA Table 3.3.2.6, which summarizes the results of AMR evaluations for the high pressure fire protection system component groups.

In LRA Section 3.3.2.1.6 and Table 3.3.2.6, the applicant identified the materials, environments, and AERMs. The materials identified include carbon steel, alloy steel, stainless steel, aluminum, cast iron, elastomers, glass, and copper alloys.

The applicant identified the environments to which these materials could be exposed as air and gas (wetted, ambient and dry), raw water (well water), treated water and AFFF and includes environments inside, outside, and buried. The applicant identified loss of material (from corrosion or leaching) and degradation (UV degradation of elastomers) as the aging effects associated with the fire water system.

<u>Staff Evaluation</u>. The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the fire protection system during the period of extended operation, as required by the regulations that govern LRA. The staff also reviewed LRA Sections of 3.3.2.6 and Table 3.3.2.6 for completeness and consistency with the GALL Report and industry experience.

On the basis of its review of the LRA, the staff found that the aging effects resulting from exposure of the fire water system components to the environments described in LRA

Table 3.3.2.6 are consistent with the GALL Report and with industry experience for these material-environment combinations. Therefore, the staff found that the applicant identified the applicable aging effects and associated AMPs and that they are appropriate for the combination of materials and environments listed.

3.3.2.3.7 Potable Water System – Summary of Aging Management Evaluation – Table 3.3.2.7

The staff reviewed LRA Table 3.3.2.7, which summarizes the results of AMR evaluations for the potable water system component groups.

In LRA Table 3.3.2.7, the applicant stated the aging effects of the potable water system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, tubing, and valves made from copper alloy and exposed to inside air, which experience no AERMs and require no AMPs; fittings and piping made from carbon and low-alloy steel in raw water for loss of material due to galvanic, general, crevice and pitting corrosion, which will be managed by the One-Time Inspection Program. LRA Section 2.3.3.7 clarifies that the raw water is potable water supplied by the city of Athens, Alabama. LRA Table 3.3.2.7 notes clarify that the water is chlorinated to prevent the growth of microorganisms, such that biofouling and MIC are not expected, but that chlorination introduces the possibility of SCC for the stainless steel components. For valves made from carbon and low-alloy steel in raw water, loss of material due to general, crevice, and pitting corrosion will be managed by the One-Time Inspection Program. For fittings made from cast iron and cast iron alloy in raw water, loss of material due to general, crevice, pitting, and galvanic corrosion will be managed by the One-Time Inspection Program. For valves made from cast iron and cast iron alloy (gray) in raw water, loss of material due to general, crevice, pitting, and galvanic corrosion will be managed by the One-Time Inspection Program. For fittings and valves made from stainless steel in raw water, crack initiation and growth due to SCC will be managed by the One-Time Inspection Program. For fittings, tubing, and valves made from copper alloy in raw water, loss of material due to crevice and pitting corrosion will be managed by the One-Time Inspection Program.

In general RAI 3.3.2.2-1 the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

The staff also noted that for the carbon and low-alloy exposed to raw water, galvanic corrosion is identified as a potential aging effect for the fittings and piping, but not for the valves. In its March 11, 2005, response to the staff's informal request February 11, 2005, the applicant clarified that galvanic corrosion is only applicable when the component is in contact with a more cathodic material, and that the valves in question are not connected to more cathodic materials. The staff found this explanation reasonable and acceptable.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the RAI, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the potable water system.

Loss of Material due to Corrosion for Copper Alloys in a Raw Water Environment. The applicant identified loss of material due to crevice and pitting corrosion for components constructed of copper alloy and stainless steel in a raw water environment on their internal surface as an AERM. The One-Time Inspection Program is credited for managing this aging effect. The staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for these material and environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Table 3.3.2.7 for the potable water system evaluates the potable (city) water as a raw water source. The actual chemistry is much milder than expected for raw water. Therefore, loss of material affecting component operation during the period of extended operation is not expected. The One-Time Inspection Program will verify this by performing a sampling inspection. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable since raw water for this system is actually potable water, which has a milder chemistry. Therefore, the potential for corrosion is low. The One-Time Inspection Program will verify that corrosion is not occurring. If corrosion is detected, additional inspections and corrective actions will be taken.

3.3.2.3.8 Ventilation System – Summary of Aging Management Evaluation – Table 3.3.2.8

The staff reviewed LRA Table 3.3.2.8, which summarizes the results of AMR evaluations for the ventilation system component groups.

In LRA Table 2.3.3-8, the applicant lists individual system components within the scope of license renewal and subject to AMR. The AMR lists the components, materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: ducting made from carbon and low-alloy steel in air/gas (internal) and elastomer - rubber and silicone rubber in air/gas (internal) experience no AERMs and require no AMPs. Elastomer - rubber and silicone rubber in air/gas (external) experience elastomer degradation due to ultraviolet radiation.

In RAI 3.3.2.1.8-1, dated December 10, 2004, the staff requested additional information regarding the applicant's claim in LRA Table 3.3.2.8 that the carbon and low-alloy steel ductwork experiences no aging effects. The staff noted that adjacent entries in LRA Table 3.3.2.8 for the same material, environment, and GALL Report reference identify a loss of material due to general corrosion. It appeared to the staff that the applicant takes exception to the GALL Report's identification of crevice corrosion, pitting corrosion, and MIC as not applicable while general corrosion is applicable. In its response, by letter November 3, 2004, the applicant confirmed that the AMR was intended to state that the applicant took exception to the GALL-identified AERMs of crevice corrosion, pitting corrosion, and MIC, because the GALL identifies these AERMs for drip pans and drain lines, which are typically wet. Instead, the applicant identifies general corrosion (in adjacent line items) and credits the One-Time Inspection Program. The staff found the applicant's response acceptable because the applicant stated that the ducting is not expected to be wetted. The staff also found that the one-time inspection will be adequate to identify a loss of material in the ducting.

The technical staff also questioned the AMR items related to elastomer - rubber and silicone rubber ductwork in air/gas and inside air. For these material/environment combinations, the applicant claims that there are no AERMs based on industry guidance. The degradation of elastomers depends on environmental factors such as the temperature, radiation levels, and presence of aggressive chemicals. Degradation can also be caused by wear (for items such as seals and vibration dampers). The staff asked the applicant to provide additional information on the above factors to justify that there are no AERMs for the elastomers, or to provide aging management for the elastomer components in the ductwork. In its response dated November 3, 2004, the applicant clarified that the elastomer degradation due to ultraviolet radiation is identified (in adjacent LRA Table 3.3.2.8 AMR items) and managed by the Systems Monitoring Program. The applicant did not identify elastomer degradation due to thermal exposure or ionizing radiation because the components in question remain below the thresholds for significant degradation from these factors. Based on the above, the staff found that the applicant had adequately addressed the concerns; therefore, the RAI 3.3.2.1.8-1 is resolved.

On the basis of its review of the information provided in the LRA (and the additional information included in the applicant's response to the above RAI, the staff found the aging effects of the above ventilation system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the ventilation system.

On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects for the ventilation system components that are not addressed by the GALL Report so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.9 Heating, Ventilation, and Air Conditioning System – Summary of Aging Management Evaluation – Table 3.3.2.9

The staff reviewed LRA Table 3.3.2.9, which summarizes the results of AMR evaluations for the HVAC system component groups.

In LRA Table 2.3.3.9, the applicant lists individual system components within the scope of license renewal and subject to AMR. The AMR lists the components, materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following:

Components in raw water (potable): for the carbon and low-alloy steel components (fittings, heat exchangers, strainers, tanks and valves), the applicant identifies loss of material due to general, crevice, pitting, and galvanic corrosion, and credits the One-Time Inspection Program. For the cast iron and cast iron alloy components (fittings, heat exchangers, pumps, and valves), the applicant identifies loss of material due to general, crevice, pitting, and galvanic corrosion, and credits the One-Time Inspection Program. In addition, for the cast iron and cast iron alloy heat exchangers, the applicant also identifies selective leaching, and credits the Selective Leaching of Materials Program (as clarified by letter dated March 11, 2005). For the stainless steel components (fittings, flexible connectors, heat exchangers, piping and valves), the applicant identifies crack initiation and growth due to SCC and loss of material due to crevice and pitting corrosion, and credits the One-Time Inspection Program. For the copper alloy components (fittings, heat exchangers, tubing, and valves), the applicant identifies loss of material due to crevice, galvanic, and pitting corrosion, and credits the One-Time Inspection Program.

Components in treated water: for the carbon and low-alloy steel components (fittings, heat exchangers, piping, strainers, tanks and valves), the applicant identifies galvanic corrosion and credits the Closed-Cycle Cooling Water System Program. For the stainless steel components (fittings, flexible connectors, piping, pumps, strainers, tubine and valves), the applicant identifies crack initiation and growth due to SCC and loss of material due to crevice and pitting corrosion, and credits the Closed-Cycle Cooling Water System Program.

Components in raw water: for carbon steel and low-alloy steel piping, the applicant identifies loss of material due to general, crevice, pitting, and galvanic corrosion, and credits the One-Time Inspection Program. For stainless steel heat exchangers, the applicant identifies crack initiation and growth due to SCC and loss of material due to crevice and pitting corrosion, and credits the One-Time Inspection Program.

In addition to the above aging effects, the applicant identifies loss of heat transfer due to particulate fouling, and credits the One-Time Inspection Program, for heat exchanger components made from aluminum alloy, copper alloy, and stainless steel in raw water (potable), raw water, and air/gas environments.

The applicant identified no aging effects and, consequently, no AMPs, for polymer components (fittings, flexible connectors, tubing and valves) in air/gas (internal) and inside air (external), elastomer ductwork and flexible connectors in air/gas (internal) or inside air (external), and copper alloy components in inside air (external).

In general RAI 3.3.2.2-1 the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

The staff asked for additional information related to elastomer components, since the applicant determined that there are no AERMs based on industry guidance. The degradation of elastomers depends on the environmental factors such as the temperature, radiation levels, and presence of aggressive chemicals (aggressive chemicals are not anticipated for this system). In its response to the staff's informal request February 11, 2005, by letter dated March 11, 2005, the applicant demonstrated that the temperature and radiation levels remain below the thresholds for which there is significant aging of the silicon and neoprene components, the neoprene coated glass material (Dupont's Ventglass). Therefore, the staff concurred with the applicant's assessment.

With respect to the polymer components, by letter dated March 11, 2005, the applicant clarified that the polymer components are molded plastic (valves), molded nylon (fittings), hypalon coated nylon (flexible connectors), and Nycoa Nylon 589 (tubing) in air/gas and inside air. The applicant stated that once the proper polymer, resistant to the environment, is chosen, there are no AERMs. The applicant further stated that industry guidance does not identify any AERMs for these polymers and environments, but that the components would be included in the Systems Monitoring Program to verify that there is no hardening or loss of material strength due to polymer degradation.

In RAI 3.3.2.1.9-2, dated October 12, 2004, the staff stated that in Table 3.3.2.1.9 the applicant claimed that there are no AERMs for this material environment combination of copper-alloy heat exchanger in inside air (external). Condensation in the heat exchangers could lead to aging effects, and there is the potential for loss of heat transfer by such mechanisms as particulate fouling. In its November 3, 2004, response, the applicant clarified that the coils are for cooling freon, so that there is no condensation. Also, due to the design of the cooling coils (no fins), they are not susceptible to particulate fouling. Since there will be no condensation on the coils and since the design is not susceptible to particulate fouling, the staff agreed with the applicant's assessment. Therefore, the staff found the applicant's response acceptable and RAI 3.3.2.1.9-2 is resolved.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found the aging effects of the above heating, ventilation, and air conditioning system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the heating, ventilation, and air conditioning system.

<u>Crack Initiation and Growth due to SCC for Copper Alloys and Stainless Steel in Raw Water Environments</u>. The applicant identified crack initiation and growth due to SCC as an AERM for heat exchangers constructed of stainless steel in a raw water environment. The applicant credited the One-Time Inspection Program to manage this aging effect. The staff inquired as to the technical basis for identifying this aging effect for this material and environment combination. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that, upon further review, the cracking aging effect was inappropriately identified for the raw water environment and should be deleted from the Table 3.3.2.9 entry for these components.

The staff concluded that the applicant's response is acceptable for this material and environment combination since the conditions for SCC are not expected to be present in the environment identified.

<u>Crack Initiation and Growth due to SCC for Stainless Steel and Cast Austenitic Stainless Steel in Treated Water Environments</u>. The applicant identified crack initiation and growth due to SCC as an AERM for fittings, flexible connectors, piping, tubing and valves constructed of stainless steel in a treated water environment. The applicant credited the Closed-Cycle Cooling Water System Program to manage this aging effect. During the onsite audit, the staff inquired as to how the Closed-Cycle Cooling Water System Program would detect cracking prior to the loss of intended function for these components. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that, upon further review, the cracking aging effect is unnecessary for these components. In addition, components were identified with cracking of stainless steel in a raw water environment in potable water, and heating, ventilation systems, and air conditioning. The applicant determined that this cracking aging effect is also unnecessary.

The staff concluded that the applicant's response is acceptable for this material and environment combination since the conditions conducive to SCC are not present in the system identified.

Loss of Material Due to Corrosion for Cast Iron and Carbon/Low Alloy Steels in an Air/Gas Environment. The applicant identified loss of material due to crevice, galvanic, general, and pitting corrosion as an AERM for heat exchangers constructed of cast iron and cast iron alloy, as well as heaters and heat exchangers constructed of carbon or low-alloy steel in an air/gas environment on their internal surface. The One-Time Inspection Program is credited for managing this aging effect. During the onsite audit, the staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for components with these material and environment combinations in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the components in the heating, ventilation, and air conditioning system located in an air/gas environment were exposed to heated and cooled circulated air. Loss of material is consistent with the GALL Report, although the GALL Report identifies only general corrosion. Based on the potential for water accumulation on or in the area of the cooling coils, additional potential aging mechanisms were identified. Actual experience based on a review of work orders and PERs demonstrates that loss of material has not been an issue for these components within this system. In particular, no instances of pitting, crevice, or galvanic corrosion were identified in this review. The One-Time Inspection Program will verify this by performing a sampling inspection. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable since these components are normally exposed to heated and cooled air and the potential for loss of material due to crevice, galvanic, and pitting corrosion is low. Loss of material due to crevice, galvanic, and pitting corrosion of these components was included since there is the potential for water accumulation near them; however, a review of past operating experience confirms that this aging effect has not been a problem. The One-Time Inspection Program will verify that loss of material is not occurring. If loss of material is detected, additional inspections and corrective actions will be taken.

Fouling Product Buildup due to Particulate for Copper Alloy and Stainless Steel in an Air/Gas Environment. The applicant identified fouling product buildup due to particulate as an AERM for heat exchangers constructed of copper alloy and stainless steel in an air/gas environment on their internal surface. The One-Time Inspection Program is credited for managing this aging effect. During the onsite audit, the staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for these material and environment combinations for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the air/gas environment to which the cooling coils are exposed is heated and cooled circulated air. The actual plant experience based on a review of work orders and problem reports demonstrates that fouling has not been an issue with this system. The One-Time Inspection Program will verify this by performing a sampling inspection. If fouling is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable. These components are normally exposed to heated and cooled air and the potential for fouling due to particulate is low.

A review of past operating experience confirms that this aging effect has not been a problem, and the One-Time Inspection Program will verify that fouling is not occurring. If fouling is detected, additional inspections and corrective actions will be taken.

Fouling Product Buildup due to Particulate for Stainless Steel in a Raw Water Environment. The applicant identified fouling product buildup due to particulate as an AERM for heat exchangers constructed of stainless steel in a raw water environment on their internal surface. The One-Time Inspection Program is credited for managing this aging effect. During the onsite audit, the staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the raw water referred to in this line item is actually potable (city) water. The chemistry of the potable water is much milder than expected for raw water. Therefore, loss of material and fouling potentially affecting component operability during the period of extended operation is not expected. The One-Time Inspection Program will verify this by performing a sampling inspection. If corrosion or fouling is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable since the raw water referred to in this line item is actually potable (city) water. The chemistry of the potable water is much milder than expected for raw water. Therefore, loss of material and fouling potentially affecting component operability during the period of extended operation is not expected. The One-Time Inspection Program will verify this by performing a sampling inspection.

No Aging Effect or Aging Management Program Identified. The applicant identified no aging effect or AMP for heat exchangers constructed of aluminum alloy and copper alloy in an outside air environment on the external surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for this material/environment combination for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the cooling coils identified in an outside environment are in the Freon cycle and the air flow over the coils is to cool the Freon. Therefore, condensation on the coils will not occur and loss of material is not identified as an aging mechanism requiring management for the period of extended operation. Air side fouling of cooling coils that have no condensation mechanism is only a problem for fin type heat exchangers. Therefore, fouling is not identified as an aging mechanism requiring management for the period of extended operation.

The staff concluded that the applicant's response is acceptable since these components are cooling coils exposed to air flow on the outside surface. The air flow is to cool Freon inside the coils; therefore, the air will be heated and condensation will not occur on these components. The applicant also identified no aging effect or AMP for heat exchangers constructed of copper alloy in an air/gas environment on their internal surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for these material and environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff onsite audit questions that Table 3.3.2.9, rows 131 and 132 are referring to the Freon side of the cooling coil and correctly identify no aging effects. The material should reference Freon in the materials description. These items are for the external surface of cooling coils and correctly identify loss of material.

The staff concluded that the applicant's response is acceptable since the components will be exposed to Freon, which is not a corrosive environment for copper alloys; and also concurred with the corrections to Table 3.3.2.9, rows 131 and 132

3.3.2.3.10 Control Air System – Summary of Aging Management Evaluation – Table 3.3.2.10

The staff reviewed LRA Table 3.3.2.10, which summarizes the results of AMR evaluations for the control air system component groups.

In LRA Table 3.3.2.10, the applicant identifies the aging effects of the control air system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: for fittings made from carbon and low-alloy steel in inside air, the applicant identifies loss of material due to general corrosion and credits the Systems Monitoring Program. For components (heat exchangers, piping, and valves) made from carbon and low-alloy steel in treated water, the applicant identifies loss of material due to general, crevice, pitting, and galvanic corrosion, and credits the Closed-Cycle Cooling Water System Program. Fittings, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found the aging effects of the above control air system component types that are not addressed by the GALL Report are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the control air system.

3.3.2.3.11 Service Air System – Summary of Aging Management Evaluation – Table 3.3.2.11

The staff reviewed LRA Table 3.3.2.11, which summarizes the results of AMR evaluations for the service air system component groups.

In LRA Section 3.3.2.11 and Table 3.3.2.11, the applicant identified the materials, environments, and AERMs. The materials identified include carbon steel, alloy steel, stainless steel, cast iron, and cast iron alloy. The applicant identified the environments to which these materials could be exposed as air gas and inside air. The applicant identified loss of material and loss of bolting function due to general corrosion.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the service air system during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed LRA Section 3.3.2.11 and Table 3.3.2.11 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant demonstrated that the effects of aging will be adequately managed 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).

3.3.2.3.12 CO_2 System – Summary of Aging Management Evaluation – Table 3.3.2.12

In Section 3.3.2.12 and LRA Table 3.3.2.12, the applicant identified the materials, environments, and AMR. The materials identified include carbon steel, alloy steel, stainless steel, aluminum, cast iron, elastomers, glass, and copper alloys. The applicant identified the environments to which these materials could be exposed as inside air and gas. The applicant identified loss of material from corrosion as the aging effect associated with the CO_2 system components.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the CO_2 system during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed LRA Section 3.3.2.12 and Table 3.3.2.12 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.3.2.3.13 Station Drainage System – Summary of Aging Management Evaluation – Table 3.3.2.13

The staff reviewed LRA Table 3.3.2.13, which summarizes the results of AMR evaluations for the station drainage system component groups.

In LRA Table 3.3.2.13, the applicant identifies the aging effects of the station drainage system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR that does not rely on the GALL Report is as follows: valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

On the basis of its review of the information provided in the LRA and the applicant's November 3, 2004, response to the staff's RAI, the staff found the applicant's assessment consistent with industry experience for this combination of material and environment. The staff did not identify any omitted aging effects or the need for any AMPs for this combination of material and environment. Therefore, the staff found that there is reasonable assurance that the intended functions of the station drainage system valves made from copper alloy and exposed to inside air will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.14 Sampling and Water Quality System – Summary of Aging Management Evaluation – Table 3.3.2.14

The staff reviewed LRA Table 3.3.2.14, which summarizes the results of AMR evaluations for the sampling and water quality system component groups.

In LRA Table 3.3.2.14, the applicant identified the aging effects of the sampling and water quality system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, heat exchangers, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Polymer components (fittings, strainers, tubing, and valves) exposed to air/gas, inside air, and treated water experience no AERMs and require no AMPs. Panel (Open sample panel) made from carbon and low-alloy steel in inside air (external) is subject to loss of material due to general corrosion.

In general RAI 3.3.2.1-1 the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

With respect to the polymer components, in its response to the staff's informal request of February 11, 2005, by letter dated March 11, 2005, the applicant clarified that the polymer components are teflon fittings in treated water, air/gas, and inside air, polymer strainers in treated water and inside air, and polymer tubing and valves in treated water, air/gas, and inside air environments. The applicant stated that once the proper polymer, resistant to the environment, is chosen, there are no AERMs. The applicant further stated that industry guidance does not identify any AERMs for this polymer and environment, but that the components would be included in the Systems Monitoring Program to verify that there is no hardening or loss of material strength due to polymer degradation.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the sampling and water quality system.

3.3.2.3.15 Building Heat System – Summary of Aging Management Evaluation – Table 3.3.2.15

The staff reviewed LRA Table 3.3.2.15, which summarizes the results of AMR evaluations for the building heat system component groups.

In LRA Table 3.3.2.15, the applicant identifies the aging effects of the building heat system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR that does not rely on the GALL Report is as follows: heaters made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.1.

On the basis of its review of the information provided in the LRA, the staff found the applicant's assessment consistent with industry experience for this combination of material and environment. The staff did not identify any omitted aging effects or the need for any AMPs for this combination of material and environment. Therefore, the staff found that there is reasonable assurance that the intended functions of the above building heat system components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.16 Raw Water Chemical Treatment System – Summary of Aging Management Evaluation – Table 3.3.2.16

The staff reviewed LRA Table 3.3.2.16, which summarizes the results of AMR evaluations for the raw water chemical treatment system component groups.

In LRA Table 3.3.2.16, the applicant identifies the aging effects of the raw water chemical treatment system components within the scope of license renewal and subject to AMR. The AMR lists the components, materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: nickel alloy components (fittings, piping, and restricting orifice) exposed to raw water experience loss of material due to biofouling, MIC, crevice and pitting corrosion, and are managed by the One-Time Inspection Program, while nickel alloy components (fittings, piping, and restricting orifice) exposed to outside air experience no AERMs and require no AMPs.

On the basis of its review of the information provided in the LRA, the staff found the aging effects of the above raw water chemical treatment system AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the raw water chemical treatment system.

Loss of Material due to Biofouling, MIC, Crevice and Pitting Corrosion for Nickel Alloys in a Raw Water Environment. The applicant identified loss of material due to biofouling, MIC, crevice and pitting corrosion for components constructed of nickel alloy in a raw water environment on their internal surface as an AERM. The One-Time Inspection Program is credited for managing this aging effect. During the onsite audit the staff inquired as to the technical basis for concluding that the One-Time Inspection Program is adequate to manage this aging effect for this material/environment combination for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the raw water referred to in this line item is a diluted raw water chemical treatment solution. The diluted chemicals in these nickel alloy components minimize any aging effects that potentially affect component operability during the period of extended operation. If corrosion is found to be present, additional inspections and corrective actions may be required by the One-Time Inspection Program.

The staff concluded that the applicant's response is acceptable since the raw water referred to in this line item is a diluted raw water chemical treatment solution. The diluted chemicals in these nickel alloy components minimize any aging effects that potentially affect component operability during the period of extended operation.

No Aging Effect or Aging Management Program Identified. The applicant identified no aging effect or AMP for fittings, piping, and valves constructed of polymer with a raw water environment on the internal surface. During the onsite audit, the staff inquired as to the technical justification for concluding that there are no aging effects for this material/environment combination for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the polymer referred to in Table 3.3.2.16 is the internal surface of polypropylene-lined carbon steel components. The LRA does not credit the lining for prevention of corrosion and this material/environment combination should be deleted.

The staff found that the applicant's response is acceptable, because the LRA does not credit the lining for prevention of corrosion on the internal surface, and also concurred with the correction to LRA Table 3.3.2.16 to delete this material/environment combination.

3.3.2.3.17 Demineralizer Backwash Air System – Summary of Aging Management Evaluation – Table 3.3.2.17

The staff reviewed LRA Table 3.3.2.17, which summarizes the results of AMR evaluations for the demineralizer backwash air system component groups.

In LRA Table 3.3.2.17, the applicant identifies the aging effects of the demineralizer backwash air system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR that does not rely on the GALL Report is as follows: traps and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Traps made from copper alloy and exposed to air/gas (internal)-pooled moisture experience loss of material due to selective leaching.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

LRA Table 3.3.2.17 identifies the Selective Leaching of Materials Program for managing the aging effects described above.

The staff's detailed review of this AMP is found in SER Section 3.0.3.1.8.

On the basis of its review of the information provided in the LRA, the staff found the applicant's assessment consistent with industry experience for this combination of material and environment. The staff did not identify any omitted aging effects or the need for any AMPs for this combination of material and environment. Therefore, the staff found that there is reasonable assurance that the intended functions of the above demineralizer backwash air system components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.18 Standby Liquid Control System – Summary of Aging Management Evaluation – Table 3.3.2.18

The staff reviewed LRA Table 3.3.2.18, which summarizes the results of AMR evaluations for the standby liquid control system component groups.

In LRA Table 3.3.2.18, the applicant identified the aging effects of the standby liquid control system components within the scope of license renewal and subject to AMR. The AMR lists the components, materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: polymer (Derlin) fittings exposed to inside air and treated water experience no aging effects and require no aging management. Fittings made of carbon and low-alloy steel and exposed to air/gas (internal) experience loss of material due to general corrosion.

In its response to the staff's informal request February 11, 2005, by letter dated March 11, 2005,
the applicant stated that the Derlin is used as insulating flanges to prevent galvanic corrosion. Based on its review of industry experience, the applicant determined that there are no AERMs for Derlin in this application. Based on its review of the standby liquid control system and the material property data sheet for Derlin, the staff concurred with the applicant's assessment.

LRA Table 3.3.2.18 identifies the One-Time Inspection Program for managing the aging effects described above.

The staff's detailed review of this AMP is found in SER Section 3.0.3.1.7.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.19 Off-Gas System – Summary of Aging Management Evaluation – Table 3.3.2.19

The staff reviewed LRA Table 3.3.2.19, which summarizes the results of AMR evaluations for the off-gas system component groups.

In LRA Table 3.3.2.19, the applicant identified the aging effects of the off-gas system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR that does not rely on the GALL Report is as follows: fittings made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Valves made of carbon and low-alloy steel in air/gas (internal) and inside air (external) are subject to loss of material due to general corrosion.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

LRA Table 3.3.2.19 identifies the following AMPs for managing the aging effects described above: One-Time Inspection Program and Systems Monitoring Program. The staff's detailed review of these AMPs is found in SER Sections 3.0.3.1.7 and 3.0.3.3.1.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.20 Emergency Equipment Cooling Water System – Summary of Aging Management Evaluation – Table 3.3.2.20

The staff reviewed LRA Table 3.3.2.20, which summarizes the results of AMR evaluations for the emergency equipment cooling water system component groups.

In LRA Table 3.3.2.20, the applicant identifies the aging effects of the emergency equipment cooling water system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, heat exchangers, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Aluminum alloy heat exchanger subcomponents in an air/gas environment experience fouling due to particulate buildup, and are managed by the One-Time Inspection Program.

In a RAI 3.3.2.1.20-1, dated October 12, 2004. the staff asked for additional justification that there are no AERMs, including a loss of heat transfer, for the copper alloy heat exchanger components in this system. In its response, by letter November 3, 2004, the applicant stated that the components in question are the u-bend connectors for the internal cooling coil in the room coolers. These components are likely to be exposed to condensation and, therefore, may experience loss of material; however, they are external to the cooler such that loss of heat transfer is not a concern. The applicant proposes to use the Systems Monitoring Program to manage the identified aging effect. The staff found that the applicant had identified the appropriate aging effects for the above component and had proposed an acceptable AMP. Therefore, the staff found this acceptable.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found the aging effects of the above emergency equipment cooling water system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the emergency equipment cooling water system. Therefore, RAI 3.3.2.1.20-1 is considered resolved.

3.3.2.3.21 Reactor Water Cleanup System – Summary of Aging Management Evaluation – Table 3.3.2.21

The staff reviewed LRA Table 3.3.2.21, which summarizes the results of AMR evaluations for the reactor water cleanup system component groups.

In LRA Table 3.3.2.21, the applicant identifies the aging effects of the reactor water cleanup system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The only AMR that does not rely on the GALL Report is as follows: valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Heat exchangers made of carbon and low-alloy steel and exposed to treated water (internal) experience loss of material due to crevice, general, and pitting corrosion.

In general RAI 3.3.2.1-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found the aging effects of the above AMR items are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects or the need for any AMPs for the above combinations of material and environment. Therefore, the staff found that there is reasonable assurance that the component intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

LRA Table 3.3.2.21 identifies the Closed-Cycle Water Cooling System Program for managing the aging effects described above.

The staff's detailed review of this AMP is found in SER Section 3.0.3.2.12.

<u>Crack Initiation and Growth due to SCC for Stainless Steel and Cast Austenitic Stainless Steel in Treated Water Environments</u>. The staff reviewed LRA Table 3.3.2.21, which summarized the results of AMR evaluations for the reactor water cleanup system component groups. The applicant identified crack initiation and growth due to SCC and change in material properties due to thermal aging as aging effects requiring management for valves constructed of stainless steel and CASS in a treated water environment. The applicant credited the ASME Section XI Inservice Inspection Program to manage these aging effects. During the onsite audit, the staff inquired as to the ASME class of these valves, whether they are currently included in the ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program, and the basis for concluding that the ASME inspection will detect changes in material properties.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the CASS valves that are included in this line item are the reactor water cleanup system 1-inch root valves providing flow to and from the recently added durability monitoring panels for

Units 2 and 3. These valves are non-nuclear Code class, therefore, the ASME Section XI Subsections IWB, IWC and IWD Inservice Inspection Program is not applicable.

The applicant further stated that thermal embrittlement degrades the mechanical properties of material (strength, ductility, toughness) as a result of prolonged exposure to high temperatures. CASS materials are susceptible to thermal embrittlement. The degree of susceptibility is dependent upon material composition and time at temperature. The maximum time these valves would be exposed to these high temperatures would be for Unit 3. The Unit 3 valves were installed in the spring 2000 refueling outage with a proposed license expiration date of July 2, 2036. This represents a potential for approximately 36.5 years of operation at the elevated temperatures. The Unit 2 valves were installed in the spring 2001 refueling outage with a proposed license expiration date of June 28, 2034, or approximately 33.5 years of operation. None of these CASS valves will be operated beyond their original 40-year design life and thermal aging has not been identified as a current license basis (40 years) issue.

The applicant referenced NRC letter, "License Renewal Issue No. 98-0030, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components," dated May 19, 2000 from Mr. C. I. Grimes (NRC) to D. J. Walters (NEI), to support its position that change in material properties due to thermal aging is not a concern for these valves, citing the results of a bounding fracture mechanics analysis for valve bodies of less than 4-inch NPS, included in Attachment 2 to this letter.

The applicant concluded that thermal aging of these 1-inch NPS CASS valves is not an AERM, based on the following considerations:

- Thermal aging is not a CLB issue and is not a concern for operation beyond forty years. These valves will be operated for less than forty years, including the period of extended operation.
- Even assuming thermal aging for valves is a CLB concern, the conclusion from the NRC's bounding fracture analysis for valves less than NPS 4 was that "a CASS valve loaded to the maximum anticipated stress can sustain a through wall crack well in excess of its wall thickness without fracturing" and "that requirements for licensees to either (a) inspect . . . of these components would represent an unnecessary duplication of effort."

However, to resolve this issue, the applicant stated that thermal aging will be identified in the LRA as being an AERM for these 1-inch NPS non-Class 1 valves, and that the Systems Monitoring Program will be identified as the AMP to perform an external visual inspection.

The staff concluded that the applicant's response is acceptable on the basis that: (1) the valves have operating lives less than 40 years; (2) NRC-sponsored fracture mechanics analyses demonstrate a high degree of flaw tolerance, including through-wall cracking; and (3) periodic external visual examination conducted as part of the Systems Monitoring Program will detect through-wall cracking, in the unlikely event that it should occur.

During the onsite audit, the staff also asked why the BWR Stress Corrosion Cracking Program is not credited for this aging effect in all cases. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.3.2.21, lines 24 and 54 refer to fittings and piping that are less than 4-inch NPS. The corresponding GALL Report Volume 2, Item IV.C1.1-i, references the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program, the Chemistry Control Program, and the One-Time Inspection Program. For fittings and piping greater than or equal to 4-inch NPS, line items 27 and 56 specify the BRW Stress Corrosion Cracking Program and the Chemistry Control Program, which is consistent with Item IV.C1.1-f. Table 3.3.2.21, line 102 credits the BWR Stress Corrosion Cracking Program and the chemistry control program for aging management of Valves-RCPB, which is consistent with IV.C1.3-c. Note that the BWR Stress Corrosion Cracking Program invokes the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program for inspection and flaw evaluation to monitor IGSCC.

The applicant further stated that LRA Table 3.3.2.21, rows 20, 49, and 93, for non-reactor coolant pressure boundary fittings, piping, and valves, respectively, incorrectly listed the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program and/or BWR Stress Corrosion Cracking Program. The correct AMPs for rows 20, 49, and 93 are the Chemistry Control Program and One-Time Inspection Program.

The staff found that the applicant's use of the ASME Code Section XI Program for components less than 4" NPS is consistent with the GALL Report, and also concurred with the applicant's corrections to LRA Table 3.3.2.21. The staff found the applicant's response to be acceptable.

3.3.2.3.22 Reactor Building Closed Cooling Water System – Summary of Aging Management Evaluation – Table 3.3.2.22

The staff reviewed LRA Table 3.3.2.22, which summarizes the results of AMR evaluations for the reactor building closed cooling water system component groups.

In LRA Table 3.3.2.22, the applicant identifies the aging effects of the reactor building closed cooling water system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, piping, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Carbon and low-alloy steel components (fittings, heat exchangers, piping, pumps, tanks, and valves) in treated water are exposed to loss of material due to general, pitting, crevice, and galvanic corrosion, and are managed by the Closed-Cycle Cooling Water System Program.

In general RAI 3.3.2.1-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the RAI, the staff found the aging effects of the above reactor building closed cooling water system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the reactor building closed cooling water system.

3.3.2.3.23 Reactor Core Isolation Cooling System – Summary of Aging Management Evaluation – Table 3.3.2.23

The staff reviewed LRA Table 3.3.2.23, which summarizes the results of AMR evaluations for the reactor core isolation cooling system component groups.

In LRA Table 3.3.2.23, the applicant identified the aging effects of the reactor core isolation cooling system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: heat exchangers, pumps, strainers, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Aluminum alloy fittings in treated water experience crack initiation and growth due to SCC and loss of material due to crevice, pitting, and galvanic corrosion, and are managed with the Chemistry Control Program and the One-Time Inspection Program. Copper alloy valves in treated water can experience loss of material due to flow-accelerated corrosion, and are managed through the Flow-Accelerated Corrosion Program.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

In RAI 3.3.2.1.23-1, dated October 12, 2004, the staff requested the applicant to explain why loss of heat transfer is not an applicable AERM for the copper alloy heat exchanger components in inside air. In its response dated November 3, 2004, the applicant clarified that these components are the connectors for the lube oil lines going to the internal copper tubes. The staff concluded that heat transfer is not an intended function for these connectors. In addition, these connectors remain above ambient temperature, such that there is no condensation that would lead to other aging effects. The staff concurred that there will be no other aging effects in the absence of condensation or pooling. Based on the above, the staff found the applicant's response acceptable.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the RAI, the staff found the aging effects of the above reactor core isolation cooling system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the reactor core isolation cooling system.

3.3.2.3.24 Auxiliary Decay Heat Removal System – Summary of Aging Management Evaluation – Table 3.3.2.24

The staff reviewed LRA Table 3.3.2.24, which summarizes the results of AMR evaluations for the auxiliary decay heat removal system component groups.

In LRA Section 3.3.2.24 and Table 3.3.2.24, the applicant identified the materials, environments, and AERMs. The materials identified include carbon steel, low-alloy steel, and stainless steel. The applicant identified the environments to which these materials could be exposed as air gas and inside air. The applicant identified loss of material from general and pitting corrosion and of bolting function due to general corrosion.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the auxiliary decay heat removal system during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed LRA Section 3.3.2.24 and Table 3.3.2.24 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.3.2.3.25 Radioactive Waste Treatment System – Summary of Aging Management Evaluation – Table 3.3.2.25

The staff reviewed LRA Table 3.3.2.25, which summarizes the results of AMR evaluations for the radioactive waste treatment system component groups.

In LRA Table 3.3.2.25, the applicant identifies the aging effects of radioactive waste treatment system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs.

Carbon and low-alloy steel components (fittings, piping, and valves) in raw water experience loss of material due to general, crevice, and pitting corrosion, galvanic corrosion, and MIC, and are managed through the One-Time Inspection Program. Carbon and low-alloy steel components (fittings, piping, and valves) in treated water experience loss of material due to general, crevice, pitting, and galvanic corrosion, and are managed by the One-Time Inspection Program. For cast iron and cast iron alloy pumps in treated water, the applicant uses the One-Time Inspection Program to manage loss of material due to general, crevice and pitting corrosion.

For elastomer (neoprene and silicon) fittings in air/gas and inside air, the applicant does not identify any AERMs or AMPs.

Additional items the technical staff was also asked to review include the following AMR line items that do not rely on the GALL Report: aluminum alloy fittings and piping in treated water may experience crack initiation and growth due to SCC and a loss of material due to crevice and pitting corrosion, and are managed by the Chemistry Control Program and the One-Time Inspection Program, while the aluminum alloy in air experiences no AERMs. For the copper alloy (bronze) fittings, the bronze in treated water may experience a loss of material due to crevice and pitting corrosion and loss of material due to selective leaching, which are managed by the One-Time Inspection Program and Selective Leaching of Materials Program, respectively, while the bronze in inside air experiences no AERMs. For the cast iron and cast iron alloy strainers, the side exposed to treated water may experience loss of material due to general, crevice, and pitting corrosion and a loss of material due to selective leaching, which are managed by the One-Time Inspection Program and the Selective Leaching of Materials

Program, respectively, while the side in inside air experiences loss of material due to general corrosion and is managed through the Systems Monitoring Program.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

In RAI 3.3.2.1.23-1, dated October 12, 2004, the staff asked for additional information related to elastomer components, since the applicant determined that there are no AERMs based on industry guidance. The degradation of elastomers depends on the environmental factors such as the temperature, radiation levels, and presence of aggressive chemicals (aggressive chemicals are not anticipated for this system). In its response dated November 3, 2004, the applicant demonstrated that the temperature and radiation levels remain below the thresholds for which there is significant aging of the silicon and neoprene. Therefore, the staff concurred with the applicant's assessment.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's responses to the RAIs, the staff found the aging effects of the above radioactive waste treatment system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the radioactive waste treatment system.

3.3.2.3.26 Fuel Pool Cooling and Cleanup System – Summary of Aging Management Evaluation – Table 3.3.2.26

The staff reviewed LRA Table 3.3.2.26, which summarizes the results of AMR evaluations for the fuel pool cooling and cleanup system component groups.

In LRA Table 3.3.2.26, the applicant identifies the aging effects of the spent fuel pool cooling and cleanup system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: for aluminum alloy components (fittings, piping, and valves) in treated water, the applicant identifies crack initiation and growth due to SCC and loss of material due to crevice and pitting corrosion, and galvanic corrosion, and credits the Chemistry Control Program and the One-Time Inspection Program.

On the basis of its review of the information provided in the LRA, the staff found the aging effects of the above spent fuel pool cooling and cleanup system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the spent fuel pool cooling and cleanup system.

3.3.2.3.27 Fuel Handling and Storage System – Summary of Aging Management Evaluation – Table 3.3.2.27

The staff reviewed LRA Table 3.3.2.27, which summarizes the results of AMR evaluations for the fuel handling and storage system component groups.

In Section 3.3.2.27 and LRA Table 3.3.2.27, the applicant identified the materials, environments, and AERMs. The materials identified include aluminum alloy, carbon steel, low-alloy steel, and stainless steel. The applicant identified the environments to which these materials could be exposed as inside air and treated water. The applicant identified loss of material from crack initiation and growth due to stress corrosion; loss of material due to crevice, pitting, general, and galvanic corrosion of bolting function due to stress relaxation; and loss of material due to mechanical wear.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the service air system during the period of extended operation, as required by 10 CFR 54.21(a)(3). Additionally, the staff considered the aging effect loss of of bolting function due to stress relaxation, which is addressed in SER Section 3.3.2.36. The staff reviewed LRA Section 3.3.2.27 and Table 3.3.2.27 for completeness and consistency with the GALL Report and industry experience.

3.3.2.3.28 Diesel Generator System – Summary of Aging Management Evaluation – Table 3.3.2.28

The staff reviewed LRA Table 3.3.2.28, which summarizes the results of AMR evaluations for the diesel generator system component groups.

In LRA Table 3.3.2.28, the applicant identifies the aging effects of the diesel generator system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, piping, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. For stainless steel fittings in treated water, the applicant identifies crack initiation/growth due to SCC and loss of material due to crevice and pitting corrosion, and credits the Closed-Cycle Cooling Water Program. For flexible connectors made from elastomer and exposed to treated water (internal) and inside air (external), the applicant identifies elastomer degradation due to thermal exposure and credits the Systems Monitoring Program. For flexible connectors made from elastomer and exposed to inside air, the applicant identifies elastomer degradation due to thermal exposure and ultraviolet radiation, and credits the Systems Monitoring Program. LRA Table 3.3.2.28 also identifies wear as an AERM for the elastomer flexible connectors, and credits the Systems Monitoring Program.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found the aging effects of the above diesel generator system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the diesel generator system.

<u>Crack Initiation and Growth due to SCC for Copper Alloys and Stainless Steel in Raw Water Environments</u>. The applicant identified crack initiation and growth due to SCC as an AERM for heat exchangers constructed of copper alloy in a raw water environment. The applicant credited the Open-Cycle Cooling Water System Program to manage this aging effect. The staff asked how the Open-Cycle Cooling Water System Program will detect cracking prior to the loss of intended function for these components. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the Open-Cycle Cooling Water System Program is implemented by a variety of maintenance, inspection, and testing procedures. The primary method of detecting cracking in heat exchangers is eddy current testing in accordance with the heat exchanger program (NEDP-17). This procedure requires the heat exchanger engineer to coordinate and schedule heat exchanger activities. The actual inspections are scheduled as preventive maintenance tasks. In particular, the diesel generator cooling water heat exchangers are scheduled with a frequency of two years.

The staff concluded that the applicant's response is acceptable for this material and environment combination since the Open-Cycle Cooling Water System Program is implemented by a variety of maintenance, inspection, and testing procedures, which include eddy current testing in accordance with the heat exchanger program. Eddy current testing will detect cracking.

3.3.2.3.29 Control Rod Drive System – Summary of Aging Management Evaluation – Table 3.3.2.29

The staff reviewed LRA Table 3.3.2.29, which summarizes the results of AMR evaluations for the CRD system component groups.

In LRA Table 3.3.2.29, the applicant identifies the aging effects of the CRD system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, heat exchangers, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Aluminum alloy fittings in treated water are subjected to crack initiation/growth due to SCC and loss of material due to crevice and pitting corrosion, and are managed by the Chemistry Control Program and the One-Time Inspection Program.

In general RAI 3.3.2.2-1, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAI, the staff found the aging effects of the above CRD system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the CRD system.

Crack Initiation and Growth due to SCC for Stainless Steel and Cast Austenitic Stainless Steel in Treated Water Environments The applicant identified loss of material due to corrosion as an AERM for fittings, piping, strainers, and valves constructed of stainless steel in a treated water environment. However, cracking due to SCC was only identified for valves. The staff inquired as to why cracking due to SCC was not identified for stainless steel fittings, piping, and strainers in a treated water environment for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that stainless steel components have the potential for corrosion if the chemistry control program is not properly implemented. However, stress corrosion cracking only requires an AMP where the normal operating temperature is greater than 140 °F. The AMR identifies that the CRD system RCPB components (valves) that interface with the reactor water cleanup system experience normal operating temperatures in excess of 140 °F. These closed valves are the only components in the CRD system that exceed 140 °F.

The staff concluded that the applicant's determination that cracking due to SCC is only applicable to RCPB valves in the CRD system is acceptable since these are the only components that operate at temperatures above 140 °F.

3.3.2.3.30 Diesel Generator Starting Air System – Summary of Aging Management Evaluation – Table 3.3.2.30

The staff reviewed LRA Table 3.3.2.30, which summarizes the results of AMR evaluations for the diesel generator starting air system component groups.

In LRA Table 3.3.2.30, the applicant identifies the aging effects of the diesel generator starting air system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, flexible connectors, piping, tubing, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Flexible connectors made of elastomer in an air/gas (internal) and inside air (external) environment exhibit no AERMs and require no AMPs. Strainers made of stainless steel in an air/gas (internal) and inside air (external) environment exhibit no AERMs and require no AMPs.

In a general RAI, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

Depending on the environmental conditions such as temperature, ultraviolet radiation, and aggressive chemicals, there is the potential for elastomers to experience aging effects and require aging management. The applicant was asked to clarify that there are no aging effects commensurate with the environment exposed to or to provide appropriate aging management for these components (as they have done for numerous other systems); however, the applicant discussed the diesel generator system instead.

By letter dated May 24, 2005 the applicant submitted additional information in regard to the management of elastomers in the diesel generator starting air system. The applicant clarified that the rubber flexible connector can be exposed to a maximum temperature of about 115 °F and, conservatively, thermal stress is considered an applicable aging effect. The applicant identified that the Systems Monitoring Program will be used to manage the external surface and the internal surface will be managed by the One-Time Inspection Program. The applicant also clarified that no specific recommendations were provided by the manufacturer regarding service life and appropriate inspections.

The staff reviewed the applicant's response and found the response to be reasonable and acceptable because the applicant identified that the external and internal surfaces of the rubber flexible connectors will be managed by the Systems Monitoring Program and the One-Time Inspection Program, respectively. There is reasonable assurance that these AMPs are capable of detecting and correcting degradation of the elastomers caused by thermal or other environmental aging factors prior to adversely affecting the intended function of the components.

On the basis of its review of the information provided in the LRA and the RAI response, the staff found the applicant's assessment consistent with industry experience for this combination of material and environment. The staff did not identify any omitted aging effects or the need for any AMPs for this combination of material and environment. Therefore, the staff found that there is reasonable assurance that the intended functions of the above components of the diesel generator starting air system will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

3.3.2.3.31 Radiation Monitoring System – Summary of Aging Management Evaluation – Table 3.3.2.31

The staff reviewed LRA Table 3.3.2.31, which summarizes the results of AMR evaluations for the radiation monitoring system component groups.

In LRA Table 3.3.2.31, the applicant identifies the aging effects of the radiation monitoring system components within the scope of license renewal and subject to AMR. The AMR lists the materials, environments, AERMs, and AMPs credited for managing the AERMs. The AMR line items that do not rely on the GALL Report include the following: fittings, pumps, strainers, and valves made from copper alloy and exposed to inside air (external environment) experience no AERMs and require no AMPs. Traps made from aluminum alloy exposed to raw water are subjected to crack initiation/growth due to SCC, and will be managed by the One-Time Inspection Program. Tubing made from polymer (tygon) in air/gas experience no AERMs and require no AMPs.

In a general RAI, the staff questioned whether the copper alloy components exposed to inside air would be subject to aging effects. The staff found the applicant's assessment of the copper alloy components to be acceptable, as discussed in SER Section 3.3.2.3.

With respect to the polymer components, in response to the staff's informal request of February 11, 2005, by letter dated March 11, 2005, the applicant clarified that the polymer components are tygon tubing in air/gas and inside air. The applicant stated that once the proper polymer, resistant to the environment, is chosen, there are no AERMs. The applicant further stated that industry guidance does not identify any AERMs for this polymer and environment, but the components would be included in the Systems Monitoring Program to verify that there is no hardening or loss of material strength due to polymer degradation.

On the basis of its review of the information provided in the LRA and the additional information included in the applicant's response to the above RAIs, the staff found the aging effects of the above radiation monitoring system component types are consistent with industry experience for these combinations of materials and environments. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the radiation monitoring system

3.3.2.3.32 Neutron Monitoring System – Summary of Aging Management Evaluation – Table 3.3.2.32

The staff reviewed LRA Table 3.3.2.32, which summarizes the results of AMR evaluations for the neutron monitoring system component groups.

In LRA Section 3.3.2.32 and Table 3.3.2.32, the applicant identified the materials, environments, and AERMs. The materials identified include carbon steel, and low-alloy steel. The applicant identified the environments to which these materials could be exposed as air gas and inside air. The applicant identified loss of material from crack initiation and growth due to stress corrosion and cyclic loading, loss of bolting function due to general corrosion and wear and loss of material due to crevice and pitting corrosion.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the neutron monitoring system during the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff reviewed LRA Section 3.3.2.32 and Table 3.3.2.32 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.3.2.3.33 Traversing In-Core Probe System – Summary of Aging Management Evaluation – Table 3.3.2.33

The staff reviewed LRA Table 3.3.2.33, which summarizes the results of AMR evaluations for the traversing in-core probe system component groups.

In LRA Section 3.3.2.33 and Table 3.3.2.33, the applicant identified the materials, environments, and AERMs. The materials identified include stainless steel. The applicant identified the environments to which these materials could be exposed as air gas and inside air. The applicant has not identified any loss of material nor any aging effects.

The staff reviewed LRA Section 3.3.2.33 and Table 3.3.2.33 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant demonstrated that the effects of aging will be adequately managed 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).

3.3.2.3.34 Cranes System – Summary of Aging Management Evaluation – Table 3.3.2.34

The staff reviewed LRA Table 3.3.2.34, which summarizes the results of AMR evaluations for the cranes system component groups.

In Section 3.3.2.34 and LRA Table 3.3.2.34, the applicant identified the materials, environments, and AERMs. The materials identified include carbon steel, and low-alloy steel. The applicant identified the environments to which these materials could be exposed as inside air. The applicant identified loss of material from crack initiation, loss of bolting function due to stress relaxation and wear, loss of material due to general corrosion and mechanical wear.

The staff reviewed the LRA to determine whether the applicant had demonstrated that it would adequately manage the effects of aging for the cranes system during the period of extended operation, as required by 10 CFR 54.21(a)(3). Additionally, the staff considered the aging effect, loss of of bolting function due to stress relaxation, which is addressed in SER Section 3.3.2.36. The staff reviewed LRA Section 3.3.2.34 and Table 3.3.2.34 for completeness and consistency with the GALL Report and industry experience.

The staff found that the applicant demonstrated that the effects of aging will be adequately managed 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).

Conclusion. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving material, environment, aging effects requiring management, and AMP combinations that are not evaluated in the GALL Report for entries shown in Table 3.3-1. The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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 reviewed LRA Table 3.3.2.9, which summarized the results of AMR evaluations for the heating, ventilation, and air conditioning system component groups.

The applicant identified no aging effect or AMP for heat exchangers constructed of aluminum alloy and copper alloy in an outside air environment on the external surface. The staff inquired as to the technical justification for concluding that there are no aging effects for this material/environment combination for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the cooling coils identified in an outside environment are in the Freon cycle and the air flow over the coils is to cool the Freon. Therefore, condensation on the coils; will not occur and loss of material is not identified as an aging mechanism requiring management for the period of extended operation. Air side fouling of cooling coils that have no condensation mechanism is only a problem for fin type heat exchangers. Therefore, fouling is not identified as an aging mechanism requiring management for the period of extended operation.

The staff concluded that the applicant's response is acceptable since these components are cooling coils exposed to air flow on the outside surface. The air flow is to cool Freon inside the coils; therefore, the air will be heated and condensation will not occur on these components. The applicant also identified no aging effect or AMP for heat exchangers constructed of copper alloy in an air/gas environment on their internal surface. The staff inquired as to the technical justification for concluding that there are no aging effects for these material and environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.3.2.9, rows 131 and 132 are referring to the Freon side of the cooling coil and correctly identify no aging effects. The material should reference Freon in the materials description. These items are for the external surface of cooling coils and correctly identify loss of material.

The staff concluded that the applicant's response is acceptable since the components will be exposed to Freon, which is not a corrosive environment for copper alloys. The staff also concurred with the corrections to Table 3.3.2.9, rows 131 and 132.

The staff reviewed LRA Table 3.3.2.2, which summarized the results of AMR evaluations for the fuel oil system component groups. The applicant identified no aging effect or AMP for components constructed of cast iron and cast iron alloy, as well as carbon or low-alloy steel in an air/gas environment on their internal surface. The staff inquired as to the technical justification for concluding that there are no aging effects for these material/environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that components in the fuel oil system are exposed to a fuel oil vapor environment. This fuel oil vapor environment protects the component surfaces and prevents internal corrosion.

The staff concluded that the applicant's determination of no AERM for components in the fuel oil system in an air/gas environment on the internal surface is acceptable since the components will be exposed to fuel oil vapor, which will protect the surfaces of the components from corrosion.

The staff reviewed LRA Table 3.3.2.3, which summarized the results of AMR evaluations for the residual heat removal service water system component groups.

The applicant identified no aging effect or AMP for components constructed of cast iron and cast iron alloy, as well as carbon or low-alloy steel in an embedded/encased environment on their external surface. The staff inquired as to the technical justification for concluding that there are no aging effects for these material and environment combinations for components in this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that no aging effects are identified for embedded/encased components. If excessive corrosion that could prevent the performance of the intended functions during the period of extended operation was detected on the inside surface or outside surface in air environments adjacent to the embedded/encased portions, corrective actions would be taken to restore the component, including the embedded/encased portions, if this was determined to be necessary.

The staff concluded that the applicant's determination of no AERM for components in the residual heat removal service water system in an embedded/encased environment is acceptable since exposure to a corrosive environment will be limited. Inspections will be performed on adjacent surfaces exposed to an air environment. If corrosion is detected on adjacent surfaces in an air environment, corrective actions will be taken to restore the component, including the embedded/encased portions, if this is determined to be necessary.

The staff reviewed LRA Table 3.3.2.16, which summarized the results of AMR evaluations for the raw water chemical treatment system component groups.

The applicant identified no aging effect or AMP for fittings, piping, and valves constructed of polymer with a raw water environment on the internal surface. The staff inquired as to the technical justification for concluding that there are no aging effects for this material/environment combination for this system. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the polymer referred to in Table 3.3.2.16 is the internal surface of polypropylene-lined carbon steel components. The LRA does not credit the lining for prevention of corrosion and this material/environment combination should be deleted.

The staff found that the applicant's response is acceptable, because the LRA does not credit the lining for prevention of corrosion on the internal surface. The staff also concurred with the correction to Table 3.3.2.16, to delete this material/environment combination.

3.3.3 Conclusion

The staff concluded that the applicant had provided sufficient information to demonstrate that the effects of aging on the auxiliary systems components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) 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 reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the auxiliary systems, as required by 10 CFR 54.21(d).

3.4 Aging Management of Steam and Power Conversion System

This section of the SER documents the staff's review of the applicant's AMR results for the steam and power conversion system components and component groups associated with the following systems:

- main steam
- condensate and demineralized water
- feedwater
- heater drains and vents
- turbine drains and miscellaneous piping
- condenser circulating water
- gland seal water

3.4.1 Summary of Technical Information in the Application

In LRA Section 3.4, the applicant provided AMR results for components. In LRA Table 3.4.1, "Summary of Aging Management Evaluations for Steam and Power Conversion System Evaluated in Chapter VIII of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the steam and power conversion system components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine if the applicant had provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components that are within the scope of license renewal and subject to an AMR will be adequately managed 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 performed an onsite audit, during the weeks of June 21 and July 26, 2004, of AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff's audit evaluation are documented in the BFN audit and review report and are summarized in SER Section 3.4.2.1.

In the onsite audit, the staff also selected AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.4.2.2. The staff's audit evaluations are documented in the audit and review report and are summarized in SER Section 3.4.2.2.

In the onsite audit, the staff conducted a technical review of the remaining AMRs that are not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects had been identified and evaluating whether the aging effects listed were appropriate for the combinations of materials and environments specified. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.4.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.4.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the steam and power conversion system components.

Table 3.4-1, below, provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.4, that are addressed in the GALL Report.

Table 3.4-1 Staff Evaluation for Steam and Power Conversion System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping and fittings in main feedwater line, steam line and in auxiliary feedwater (AFW) piping (PWR only) (Item Number 3.4.1.1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue
Piping and fittings, valve bodies and bonnets, pump casings, tanks, tubes, tubesheets, channel head and shell (except main steam system) (Item Number 3.4.1.2)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Chemistry Control Program; One-Time Inspection Program	Chemistry Control Program; One-Time Inspection Program	Consistent with GALL which recommends further evaluation (See Section 3.4.2.2.2)
External surface of carbon steel components (Item Number 3.4.1.5)	Loss of material due to general corrosion	Plant-specific	Systems Monitoring Program	See Section 3.4.2.2.4

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Carbon steel piping and valve bodies (Item Number 3.4.1.6)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion Program	Flow-Accelerated Corrosion Program	Consistent with GALL which recommends no further evaluation (See Section 3.4.2.1)
Carbon steel piping and valve bodies to main steam system (Item Number 3.4.1.7)	Loss of material due to pitting and crevice corrosion	Chemistry Control Program	Chemistry Control Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.4.2.1)
Closure bolting in high-pressure or high-temperature systems (Item Number 3.4.1.8)	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and/or SCC	Bolting Integrity Program	Bolting Integrity Program	Consistent with GALL with exceptions, which recommends no further evaluation (See Section 3.4.2.1)
Heat exchangers and coolers/condensers serviced by open-cycle cooling water (Item Number 3.4.1.9)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion, MIC, and biofouling; buildup of deposit due to biofouling	Open-Cycle Cooling Water System Program	Open-Cycle Cooling Water System Program	Consistent with GALL which recommends no further evaluation (See Section 3.4.2.1)
Heat exchangers and coolers/condensers serviced by closed-cycle cooling water (Item Number 3.4.1.10)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Closed-Cycle Cooling Water System Program	Closed-Cycle Cooling Water System Program	Consistent with GALL which recommends no further evaluation (See Section 3.4.2.1)
External surface of aboveground condensate storage tank (Item Number 3.4.1.11)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Aboveground Carbon Steel Tanks Program	Aboveground Carbon Steel Tanks Program	Consistent with GALL which recommends no further evaluation (See Section 3.4.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
External surface of buried condensate storage tank and AFW piping (Item Number 3.4.1.12)	Loss of material due to general, pitting, and crevice corrosion; MIC	Buried piping and tanks surveillance Buried piping and tanks inspection	N/A	Not applicable At BFN, the condensate storage tanks and piping and fittings associated with the condensate storage tank are not located underground

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.4.2.1, involves the staff's review of the AMR results for components in the steam and power conversion system that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.4.2.2, involves the staff's review of the AMR results for components in the steam and power conversion systems that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.4.2.3, involves the staff's review of the AMR results for components in the steam and power conversion system that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the steam and power conversion system components is documented in SER Section 3.0.3.

3.4.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Not Recommended

Summary of Technical Information in the Application. In LRA Section 3.4.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the steam and power conversion system components:

- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program
- Bolting Integrity Program
- BWR stress corrosion cracking program
- Chemistry Control Program
- Compressed Air Monitoring Program
- Flow-Accelerated Corrosion Program
- One-Time Inspection Program
- Systems Monitoring Program
- Aboveground Carbon Steel Tanks Program
- Selective Leaching of Materials Program
- Buried Piping and Tanks Inspection Program

Staff Evaluation. In LRA Tables 3.4.2-1 through 3.4.2-7, the applicant provided a summary of AMRs for the steam and power conversion system components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated that the AMR was consistent with the GALL Report.

Note A indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated that the component for the AMR line item is different from but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated that the component for the AMR line item is different from but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicated that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR was valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the BFN audit and review report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

For aging management evaluations that the applicant stated are consistent with the GALL Report and for which further evaluation is not recommended, the staff conducted its audit to determine whether the applicant's reference to the GALL Report in the LRA is acceptable.

The staff reviewed the LRA to confirm that the applicant had (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects are reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the steam and power conversion system components that are subject to an AMR.

On the basis of its audit, the staff determined that for AMRs not requiring further evaluation, as identified in LRA Table 3.4.1 (Table 1), the applicant's references to the GALL Report are acceptable, and no further staff review is required.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concluded that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR54.21(a)(3).

3.4.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.4.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the steam and power conversion system. For some line items consistent with the GALL Report in LRA Tables 3.4.2-1 through 3.4.2-7 (LRA Table 2 in each section), the applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to general, pitting, and crevice corrosion
- loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling
- general corrosion

- loss of material due to general, pitting, crevice corrosion, and MIC
- quality assurance for aging management of NSR components

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it had adequately addressed the issues that the applicant further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.4.2.2. Details of the staff's audit are documented in the staff's audit and review report. The staff's evaluation of the aging effects is discussed in the following sections.

3.4.2.2.1 Cumulative Fatigue Damage

In LRA Section 3.3.2.2.3, the applicant stated that fatigue is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.3 documents the staff's review of the applicant's evaluation of this TLAA.

3.4.2.2.2 Loss of Material due to General, Pitting, and Crevice Corrosion

The staff reviewed the LRA Section 3.4.2.2.2 against the criteria in SRP-LR Section 3.4.2.2.2.

SRP-LR Section 3.4.2.2.2 states that loss of material due to general, pitting, and crevice corrosion should be evaluated further for carbon steel piping and fittings, valve bodies and bonnets, pump casings, pump suction and discharge lines, tanks, tubesheets, channel heads, and shells except for main steam system components; and that loss of material due to pitting and crevice corrosion should be evaluated further for stainless steel tanks and heat exchanger/cooler tubes. The Chemistry Control Program relies on monitoring and control of water chemistry based on the guidelines in BWRVIP-79 (EPRI TR-103515) for water chemistry in BWRs; however, corrosion may occur at locations of stagnant flow conditions. Therefore, the effectiveness of the Chemistry Control Program should be verified to ensure that corrosion is not occurring. The GALL Report recommends further evaluation of programs to manage loss of material due to general, pitting, and crevice corrosion to verify the effectiveness of the Chemistry Control Program. A one-time inspection of selected components and susceptible locations is an acceptable method to ensure that corrosion is not occurring and that the components' intended function will be maintained during the period of extended operation. The AMP recommended by the GALL Report is XI.M32, "One-Time Inspection."

In LRA Section 3.4.2.2.2, the applicant credits the Chemistry Control Program to manage loss of material for the components requiring further evaluation. The applicant addressed the GALL Report recommendation for further evaluation to verify the effectiveness of the chemistry control through the One-Time Inspection Program. The staff reviewed the Chemical Instruction (CI) 13.1, Chemistry Program, Revision 20, which implements chemistry control of primary water used in the steam and power conversion system. The implementing procedure recommends that the effectiveness of the Chemistry Control Program should be verified by means of tools like plant action levels at cut-off points established for contaminant concentrations recommended by Industry guidance to ensure that corrosion is not occurring, with corrective actions if these are exceeded. The staff did not find any instances of exceeding action level II or III in the past five years of operation (i.e., levels exceeding O_2 > 100 ppb or chlorides > 150 ppb or sulfates > 150 ppb). The staff concluded that the applicant had satisfactorily complied with GALL recommendations in managing this aging effect and demonstrated that the effects of aging for loss of material will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.3 Loss of Material due to General, Pitting, and Crevice Corrosion, Microbiologically Influenced Corrosion, and Biofouling

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.4.2.2.4 General Corrosion

The staff reviewed the LRA Section 3.4.2.2.4 against the criteria in SRP-LR Section 3.4.2.2.4.

SRP-LR Section 3.4.2.2.4 states that loss of material due to general corrosion could occur on the external surfaces of all carbon steel SCs, including closure bolting exposed to operating temperature less than 212 °F. The GALL Report recommends further plant-specific evaluation to ensure that this aging effect is adequately managed.

In LRA Section 3.4.2.2.4, the applicant stated that it will implement the Systems Monitoring Program to manage general corrosion of external surfaces exposed to operating temperatures less than 212 °F.

The applicant credits the Systems Monitoring Program to manage general corrosion of external surfaces exposed to operating temperatures less than 212 °F. This is consistent with the GALL Report. The staff accepted the Systems Monitoring Program, and its evaluation of this program is documented in SER Section 3.0.3.3.1.

The staff found that the applicant demonstrated that the effects of aging for loss of material will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.5 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion

Consistent with the SRP-LR, this further evaluation only applies to PWRs. Therefore, it is not applicable to BFN.

3.4.2.2.6 Quality Assurance for Aging Management of Non-Safety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's quality assurance program.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determines that (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.4.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.4.2.1 through 3.4.2.7, the staff reviewed additional details of the results of the AMRs for MEAP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report. The components impacted by the AMRs are from the following steam and power conversion systems:

- Table 3.4.2.1: Main Steam System (001)
- Table 3.4.2.2: Condensate and Demineralized Water System (002)
- Table 3.4.2.3: Feedwater System (003)
- Table 3.4.2.4: Heater Drains and Vents System (006)
- Table 3.4.2.5: Turbine Drains and Miscellaneous Piping System (008)
- Table 3.4.2.6: Condenser Circulating Water System (027)
- Table 3.4.2.7: Gland Seal Water System (037)

In LRA Tables 3.4.2.1 through 3.4.2.7, the applicant indicated, via Notes F through J, that combinations of component type, material, environment, and AERM do not correspond to a line item in the GALL Report, and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. For component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

In RAI 3.4-1, dated November 18, 2004, the staff stated that in LRA Tables 3.4.2.1 through 3.4.2.7, carbon and low-alloy steel bolting in an inside air (external) or outside air (external) environment is not identified with the aging effect of cracking requiring management. In RAI 3.4-1, dated November 18, 2004, the staff requested the applicant to discuss the specific material grading used for the bolting in each of the associated systems, and justify the basis for concluding that crack initiation/growth due to SCC is not a concern for the bolting during the period of extended operation. In its response, by letter dated December 16, 2004, the applicant stated that the cracking aging effect is not identified because high-yield bolting materials (yield strength above 150 ksi) had not been identified and a review of the BFN operating experience had not identified any instances where mechanical component failure was attributable to SCC of high-strength bolting. In addition, the use of molybdenum disulfide thread lubricant, which is considered to promote SCC, is not allowed by site and engineering procedures. Therefore, loss of bolting function due to SCC of bolted joints of vendor-supplied mechanical equipment is not expected and no aging management is required for the period of extended operation.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-1 is resolved.

In RAI 3.4-2, dated November 18, 2004, the staff stated that in LRA Tables 3.4.2.2, 3.4.2.3, 3.4.2.6, and 3.4.2.7, copper-alloy components in an inside air (external) environment are not identified with any aging effects requiring management. Therefore, the staff requested the applicant to provide a discussion of the air environment involved, and to justify the basis for concluding that there are no aging effects requiring management under the material/environment combinations. The staff also requested the applicant to provide a summary description of the stated industry guidance. In its response, by letter dated December 16, 2004, the applicant stated that the copper-alloy components exposed to an inside air (external) environment were evaluated individually to determine where condensation or periodic wetting could occur. Copper-alloy components containing fluid at a temperature below the dew point of the external environment is subject to condensation. The identified aging effects/mechanisms were then determined based on the particular copper alloy present and whether condensation or periodic wetting could occur. Based on this evaluation, the applicant concluded that there were no instances where copper-alloy components with greater than 15 percent zinc were subject to an aggressive environment or condensation/periodic wetting. Therefore, no aging effects that require management during the period of extended operation were identified for the copper-alloy components in the subject tables. The applicant also provided a summary description of the industry guidance (i.e., EPRI Technical Report 1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools"), which supports the above finding for copper alloy.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-2 is resolved.

In RAI 3.4-3, dated November 18, 2004, the staff stated that in LRA Tables 3.4.2.1, 3.4.2.3, 3.4.2.4, and 3.4.2.5, carbon and low-alloy steel bolting in an inside air (external) environment is not identified with any aging effects requiring management. Also, the applicant indicated that carbon and low-alloy steels are not susceptible to external general corrosion when the temperature is greater than 212 °F. Therefore, the staff requested the applicant to discuss the specific temperature environment for bolting, instead of piping, and to justify the basis for concluding that no aging effects need to be identified for the bolting.

In its response, by letter dated December 16, 2004, the applicant stated that LRA Table 3.4.2.1 for the main steam system, LRA Table 3.4.2.3 for the feedwater system, LRA Table 3.4.2.4 for the heater drain and vents system, and LRA Table 3.4.2.5 for the turbine drains and miscellaneous piping system do not identify general corrosion as an aging effect for carbon and low-alloy steel bolting in an inside air (external) environment as this bolting is maintained dry by the heat to which it is exposed. The applicant stated that during normal operations the internal environment for those portions of the above systems within the scope of license renewal is much higher than 212 °F (>300 °F). Since the bolting connections are constantly in contact with the high temperature components within these systems, the bolting itself within these systems will experience temperatures higher than 212°F. Carbon and low-alloy steels are not susceptible to external general corrosion at temperatures above 212°F.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-3 is resolved.

In RAI 3.4-4, dated November 18, 2004, the staff stated that in LRA Table 3.4.2.3, carbon and low-alloy steel components in air/gas (internal) - moist air environments are identified as being susceptible to loss of material due to crevice, galvanic, general, and pitting corrosion. In lieu of a periodic inspection program, the One-Time Inspection Program is credited as the only applicable AMP. In LRA Table 3.4.2.6, carbon and low-alloy steel and cast iron and cast iron-alloy components in raw water (internal) environments are identified as being susceptible to loss of material due to biofouling, MIC, crevice, general, and pitting corrosion. The One-Time Inspection Program is credited as the only applicable AMP. Therefore, the staff requested the applicant to provide justification that the One-Time Inspection program, instead of the Periodic Inspection Program, should be used to manage the aging effects for the above components and material/environment combinations.

In its response, by letter dated December 16, 2004, the applicant stated that the carbon and low-alloy steel components in LRA Table 3.4.2.3 for the feedwater system are exposed to an air/gas--moist air environment in two applications. The first application is the small segment between the dual isolation valves on system vents and drains, and the second application is valve packing leakoff lines on Unit 1 feedwater isolation valves. These leakoff lines will be removed prior to Unit 1 restart, and will not be applicable to the LRA.

The small segment of piping/fittings between the dual isolation valves on system vents and drains is exposed to feedwater quality water when the valves are open to support maintenance activities and has trapped air with varying amount of feedwater, based on how the valves are closed (i.e., the sequence and time between valve closings). The applicant stated that the safety consequences for this short segment of piping failing are minimal as this line is downstream of a closed isolation valve that is manually opened only to support maintenance activities. Minimal degradation is expected based on the quality of the water potentially in these components. For completeness, however, and using the One-Time Inspection Program the applicant will perform inspections to verify that these lines are not degrading. Based on the expected minimal degradation as stated in the above, the staff considered the applicant's proposed use of the One-Time Inspection Program to be acceptable.

In LRA Table 3.4.2.6, for the condenser circulating water system, carbon and low-alloy steel and cast iron and cast iron-alloy components in raw water (internal) environments are identified as being susceptible to loss of material due to biofouling, MIC, crevice, general, and pitting corrosion. The in-scope components in the condenser circulating water system are those components that provide the anti-siphon vacuum breaker function. The applicant stated that upon re-reviewing the license renewal scope for the condenser circulating water system, it was determined that raw water was inadvertently specified as the internal environment for the anti-siphon vacuum breaker components. The applicable internal environment (air/gas) has already been evaluated for this system and is included in the LRA. The raw water environment will be deleted from this system.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-4 is resolved.

In RAI 3.4-5, dated November 18, 2004, the staff stated that in LRA Tables 3.4.2.1 and 3.4.2.3, bolting made of carbon and low-alloy steel, nickel alloy, and stainless steel in inside air (external) environments are identified as being susceptible to loss of bolting function due to wear. The Bolting Integrity Program is credited as the AMP. The staff noted that LRA Section B.2.1.16 does not specifically address "loss of bolting function" due to wear as an aging effect to be managed by the AMP. Therefore, the staff requested the applicant to discuss how the identified aging effect will be managed by the program.

In its response, by letter dated December 16, 2004, the applicant stated that bolting degradation due to wear (fretting) could occur at locations of repeated relative motion of mechanical component bolted joints. Wear of bolted joint components is generally not a concern; however, for license renewal purposes, wear is being assumed as a potential mechanism for "critical bolting applications." "Critical bolting applications" constitute reactor coolant pressure boundary components where closure bolting failure could result in loss of reactor coolant and jeopardize safe operation of the plant. Loss of material function due to wear is managed by the Bolting Integrity Program. This program specifies inspection requirements in accordance with ASME Code Section XI and recommendations of EPRI NP-5769. These inspection requirements include visual inspections looking for wear as well as for cracks, corrosion, and physical damage on the surface.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-5 is resolved.

In RAI 3.4-6, dated November 18, 2004, the staff stated that in LRA Table 3.4.2.2, aluminum-alloy fittings and piping in a treated-water (internal) environment are identified as being susceptible to crack initiation/growth due to SCC and loss of material due to crevice, galvanic, and pitting corrosion. Therefore, the staff requested the applicant to explain (1) why loss of material due to general corrosion is not identified as a potential AERM, (2) why FAC is not a concern for the portion of the condensate system that contains single phase fluid with temperatures less than 200 °F, and (3) how the Chemistry Control Program is used to manage the aging effects of the components/material/environment combinations identified above.

In its response, by letter dated December 16, 2004, the applicant stated that as per industry guidance, aluminum and aluminum-based alloys are not susceptible to loss of material due to general corrosion. The applicant also stated that FAC is only associated with carbon and low-alloy steels; therefore, it would not be identified as an aging mechanism for the aluminum-alloy components. Also, the portions of the condensate system that are within the license renewal boundary are the supply lines to the emergency core cooling pumps. These lines contain single phase fluid with temperatures significantly less than 200 °F with only periodic flow. Consequently, erosion/corrosion is not an aging mechanism that must be managed for the period of extended operation in the condensate system.

The applicant stated that the main objective of the Chemistry Control Program is to minimize loss of material due to general, crevice, and pitting corrosion and crack initiation and growth caused by SCC. Corrosion and cracking of aluminum alloys in treated water is managed by maintaining oxygen, chlorides, and sulfates within the limits of the Chemistry Control Program. The specific chemistry limits are the same as the limits used to manage aging of carbon/low-alloy and stainless steel components in a treated-water environment. The applicant stated that the use of the Chemistry Control Program is consistent with industry practice as identified in its past precedence review. The One-Time Inspection Program is used to verify the Chemistry Control Program's effectiveness.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-6 is resolved.

In RAI 3.4-7, dated November 18, 2004, the staff stated that in LRA Table 3.4.2.2, polymer fittings in an inside air (external) or treated-water (internal) environment are not identified with any aging effects. Therefore, the staff requested the applicant to provide a discussion of the air and treated-water environments involved and justify the basis for concluding that there are no aging effects requiring management under such material/environment combinations.

In its response, by letter dated December 16, 2004, the applicant stated that polymer fittings in LRA Table 3.4.2.2 within the condensate system are the insulation couplings between carbon steel and stainless steel pipe, and between aluminum and stainless steel pipe. Acetal (the generic name for a family of polymer products that includes DELRIN) provides high strength and stiffness along with increased dimensional stability and ease of machining. The applicant stated that a review of available industry information did not identify any aging effects for DELRIN that would be attributable to the treated-water (internal) environment or the inside air (external) environment.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-7 is resolved.

In RAI 3.4-8, dated November 18, 2004, the staff stated that in LRA Table 3.4.2.2, aluminum-alloy fittings in a treated-water (internal) environment are identified as being susceptible to crack initiation/growth due to SCC and loss of material due to crevice and pitting corrosion. Therefore, the staff requested the applicant to explain why loss of material due to general and galvanic corrosion is not identified as a potential AERM during the period of extended operation. The staff also requested the applicant to explain how the Chemistry Control Program, with the association of One-Time Inspection Program, is used to manage the identified aging effects.

In its response, by letter dated December 16, 2004, the applicant stated that as per industry guidance, aluminum and aluminum-based alloys in a treated-water environment are not susceptible to loss of material due to general corrosion. In addition, the applicant stated that the aluminum valves listed in LRA Table 3.4.2.2 as being within the condensate system are not in contact with more cathodic materials. Therefore, galvanic corrosion is not a concern for aluminum valves in a treated-water environment for the condensate system.

The applicant also stated that the main objective of the Chemistry Control Program is to minimize loss of material due to general, crevice, and pitting corrosion and crack initiation and growth caused by SCC. Corrosion and cracking of aluminum alloys in treated water is managed by maintaining oxygen, chlorides, and sulfates within the limits of the Chemistry Control Program. The specific chemistry limits are the same as the limits used to manage aging of carbon/low-alloy and stainless steel components in a treated-water environment. The applicant stated that the use of the Chemistry Control Program is consistent with industry practice as identified in its past precedence review. The One-Time Inspection program is used to verify the Chemistry Control Program's effectiveness as recommended by the GALL Report.

After evaluating the applicant's identification of aging effects for each of the above components, the staff evaluated the AMPs to determine whether they are appropriate for managing the identified aging effects. The staff also determined that the UFSAR Supplement contains an adequate description of the program.

Based on the above information provided by the applicant, the staff's concern described in RAI 3.4-8 is resolved.

In RAI 3.4-9, dated November 18, 2004, the staff stated that in LRA Table 3.4.2.3, stainless steel fittings, piping, valves, and restricting orifices forming the reactor coolant pressure boundary (RCPB) in an air/gas (internal), moist air environment are identified as being susceptible to crack initiation/growth due to SCC and loss of material due to crevice and pitting corrosion. Also, CASS valves in an RCPB in an air/gas (internal), moist air environment are identified as susceptible to change in material properties/reduction in fracture toughness due to thermal aging. The One-Time Inspection Program is credited to manage the identified aging effects. Therefore, the staff requested the applicant to provide justification that the One-Time Inspection Program alone, in lieu of a more appropriate periodic inspection program, should be used to manage the identified aging effects for the above-mentioned components and material/environment combinations.

In its response, by letter dated December 16, 2004, the applicant stated that the stainless steel reactor coolant pressure boundary components in Table 3.4.2.3, for the feedwater system, are exposed to an air/gas environment when air is trapped in the vessel flange leak detection line when the vessel head is secured. The air/gas environment is considered moist air because the trapped air is not dried and there is a small potential for leakage. The aging effects are conservatively identified as a moist air environment.

The applicant stated that fittings are addressed in rows 19 and 20 of LRA Table 3.4.2.3. The AMPs identified for cracking are the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program and the One-Time Inspection Program. The applicant stated that these same aging effects and AMPs should be shown for each applicable component (i.e., piping in rows 40 and 41, and restricting orifices in line item 46). Because of that, line item 46 in the table should be replaced by two line items with aging effects/mechanisms and AMPs similar to those in rows 40 and 41. Valves are addressed in rows 68 and 69. The BWR Stress Corrosion Cracking Program, instead of the One-Time Inspection Program, is the appropriate AMP for the cracking aging effect of stainless steel RCPB valves in line item 68, which should be corrected accordingly. For the cracking aging effect for piping components less than 4 inches NPS, GALL Report Item IV.C1.1-I states, "a plant-specific destructive examination or a nondestructive examination (NDE) that permits inspection of the inside surfaces of the piping is to be conducted to ensure that cracking has not occurred and the component intended function will be maintained during the extended period of operation." The applicant has included this small bore piping inspection in the One-Time Inspection Program.

For loss of material due to crevice and pitting corrosion, the One-Time Inspection Program is credited as an AMP because corrosion is not expected to occur for the stainless steel components in an air/gas (internal) with moist air environment. The piping is not subject to condensation and is dry except for the abnormal case when reactor vessel flange leakage occurs. The applicant stated that any water that is introduced to this line is reactor grade treated water and, as such, has minimal potential for corrosion.

The applicant stated that thermal aging of CASS valves is addressed in line item 67, where an incorrect AMP was identified. The correct AMP is the ASME Section XI Subsection IWB, IWC, and IWD Inservice Inspection Program. Therefore, line item 67 should be corrected accordingly.

Based on the above updated information, the staff considered that the applicant had adequately addressed its concern regarding the use of the One-Time Inspection Program as the sole AMP for the identified aging effects. Therefore, the staff's concern described in RAI 3.4-9 is resolved.

3.4.2.3.1 Main Steam System – Summary of Aging Management Evaluation – Table 3.4.2.1

The staff reviewed LRA Table 3.4.2.1, which summarizes the results of AMR evaluations for the main steam system component groups.

In LRA Table 3.4.2.1, the applicant identified no aging effects for stainless steel and carbon and low-alloy steel components exposed to air, for piping and tubing component types. Air is not identified in the GALL Report as an environment for these components and materials.

On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. The external environments being referred to are typical of ambient air (e.g., under a shelter, indoor, or air-conditioned enclosure or room). Therefore, the staff concluded that there are no aging effects requiring management for stainless steel in an air environment.

In LRA Table 3.4.2.1, the applicant identified no aging effects for carbon and low-alloy steel condenser components. No aging effects were identified by the AMR for the main condenser components made of carbon steel, or stainless steel in a treated-water environment or inside air. These materials have successfully performed as main condenser materials at other plants. Further, the applicant 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 main steam isolation valve (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 concurred 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.

3.4.2.3.2 Condensate and Demineralized Water System – Summary of Aging Management Evaluation – Table 3.4.2.2

The staff reviewed LRA Table 3.4.2.2, which summarizes the results of AMR evaluations for the condensate and demineralized water system component groups.

In LRA Table 3.4.2.2, the applicant identified no aging effects for stainless, carbon, and low-alloy steel components exposed to air for piping and tubing component types. Air is not identified in the GALL Report as an environment for these components and materials.

On the basis of current industry research and operating experience, dry air on metal will not result in aging that will be of concern during the period of extended operation. Therefore, the staff concluded that there are no AERMS for stainless, carbon, and low-alloy steel in an air environment.

In LRA Table 3.4.2.2, the applicant identified an aging effect of galvanic corrosion for carbon and low-alloy steel components exposed to treated water internally. The GALL Report does not indicate the aging effect, but recommends further evaluation for these components.

In managing the galvanic aging effect, the applicant stated that galvanic corrosion can only progress if the dissimilar metals are in contact in the presence of an electrolyte. Control of galvanic corrosion in treated water systems is possible by maintaining adequate chemistry controls. As treated water is a poor electrolyte, the dissimilar metals in this environment would experience little or no galvanic corrosion. This is evidenced by the lack of industry operating experience of galvanic corrosion failures in treated water systems. A review of BFN PERs and work orders did not identify instances where galvanic corrosion was a failure mechanism.

The staff found that the applicant demonstrated that the effects of aging for loss of material due to galvanic corrosion will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

In LRA Table 3.4.2.2, aluminum-alloy fittings in a treated-water environment are identified as being susceptible to crack initiation/growth due to SCC and loss of material due to crevice, galvanic, and pitting corrosion. Since this material was not listed in the GALL Report, the staff needed some additional explanation to justify the Chemistry Control Program and One-Time Inspection Program to manage the effect.

The applicant stated that the aging effects identified for aluminum alloys are consistent with EPRI Report 1003056, "Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3." Aluminum alloys were evaluated using the guidelines given in the report. BFN utilizes the Chemistry Control Program and One-Time Inspection Program to manage the effect, which is also the industry standard; based on past precedents review of similar applications for managing the aging effects of aluminum alloys in treated-water environments, the staff found the response acceptable.

In LRA Table 3.4.2.2, for carbon and low-alloy steel piping in air/gas environment (internal) the applicant mentions only one-time inspection for aging management due to general corrosion.

GALL Table VIII.E.1, Condensate System, does not address the air/gas environment identified in the LRA.

The applicant clarified that the row 35 environment in LRA Table 3.4.2.2 referred to the area between the two isolation valves on condensate system vents and drains. This small segment of piping is exposed to condensate flow when the valves are open and has air trapped with varying amount of condensate based on how the valves are closed, that is, the sequence and time between valve closings. The safety consequences for this short segment of piping failing are non-existent, because this line is downstream of a closed isolation valve. However, for completeness and to verify that these lines are not degrading, the applicant will perform some inspections using the One-Time Inspection Program, even though the GALL Report does not address the air/gas environment.

3.4.2.3.3 Feedwater System – Summary of Aging Management Evaluation – Table 3.4.2.3

The staff reviewed LRA Table 3.4.2.3, which summarizes the results of AMR evaluations for the feedwater system component groups.

In LRA Table 3.4.2.3, stainless steel fittings (item 11) in a treated water environment are identified as being susceptible to crack initiation and SCC, which is not identified in GALL Report (VIIID2.1.1-b) for this item.

The applicant stated in Mechanical Evaluation Report - Feedwater System 003 that the shape of components in this system made from stainless steel material may present a high stress environment, and the treated water may contain contaminants such as chlorides and sulfides. This combination, with temperatures above 140 °F, may promote SCC. This conclusion is supported by evidence from industry experience. The staff concurred with the applicant that this aging effect needed appropriate evaluation and managing. The staff agreed that the proposed management through the Chemistry Control Program and One-Time Inspection Program will be adequate to manage the aging.

3.4.3 Conclusion

The staff concluded that the applicant had provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) 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 reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the steam and power conversion system, as required by 10 CFR 54.21(d).

3.5 Aging Management of Containments, Structures, and Component Supports

This section of the SER documents the staff's review of the applicant's AMR results for the containments, structures, and component supports components and component groups associated with the following systems:

- primary containment structures
- reactor buildings
- equipment access lock
- diesel generator buildings
- standby gas treatment building
- off-gas treatment building
- vacuum pipe building
- residual heat removal service water tunnels
- electrical cable tunnel from intake pumping station to the powerhouse
- underground concrete encased structures
- earth berm
- intake pumping station
- gate structure No. 3
- intake channel
- north bank of cool water channel east of gate structure No. 2
- south dike of cool water channel between gate structure Nos. 2 and 3
- condensate water storage tanks' foundations and trenches
- containment atmosphere dilution storage tanks' foundations
- reinforced concrete chimney
- turbine buildings
- diesel high-pressure fire pump house
- vent vaults
- transformer yard
- 161 kV (kiloVolt) switchyard
- 500 kV switchyard
- structures and component supports commodities group

3.5.1 Summary of Technical Information in the Application

In LRA Section 3.5, the applicant provided AMR results for components. In LRA Table 3.5.1, "Summary of Aging Management Evaluations for Structures and Component Supports Evaluated in Chapter II and III of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the containments, structures, and component supports components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of the AERM. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify the AERM. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine whether the applicant had provided sufficient information to demonstrate that the effects of aging for the containments, structures, and component supports components that are within the scope of license renewal and subject to an AMR will be adequately managed 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).

During the weeks of June 21 and July 26, 2004, the staff performed an onsite audit, of AMRs to confirm the applicant's claim that certain identified AMRs are consistent with the GALL matters described in the GALL Report. The staff verified that the material presented in the LRA is applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Detail of the staff's audit evaluation are documented in the BFN audit and review report, and are summarized in SER Section 3.5.2.1.

In the onsite audit, the staff also selected AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the acceptance criteria in SRP-LR Section 3.5.2.2, dated July 2001. The staff's audit evaluations are documented in the BFN audit and review report, and are summarized in SER Section 3.5.2.2.

In the onsite audit, the staff also conducted a technical review of the remaining AMRs that are not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects had been identified and evaluating whether the aging effects listed are appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the BFN audit and review report, and are summarized in SER Section 3.5.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.5.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the containments, structures, and component supports components.

Table 3.5-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.5 that are addressed in the GALL Report.

Table 3.5-1 Staff Evaluation for Containments, Structures, and Component Supports in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Penetration sleeves, penetration bellows, and dissimilar metal welds	Cumulative fatigue damage	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.6, Primary Containment Fatigue

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Penetration sleeves, bellows, and dissimilar metal welds (Item Number 3.5.1.2)	Cracking due to cyclic loading, crack initiation and growth due to SCC	Containment Inservice Inspection (ISI) Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.5.2.1)
Penetration sleeves, penetration bellows, and dissimilar metal welds (Item Number 3.5.1.3)	Loss of material due to corrosion	Containment ISI Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Personnel airlock and equipment hatch (Item Number 3.5.1.4)	Loss of material due to corrosion	Containment ISI Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Personnel airlock and equipment hatch (Item Number 3.5.1.5)	Loss of leak tightness in closed position due to mechanical wear of locks, hinges, and closure mechanisms	Containment Leak Rate Test Program; Plant Technical Specifications Program	Containment Leak Rate Test Program; Plant Technical Specifications Program	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Seals, gaskets, and moisture barriers (Item Number 3.5.1.6)	Loss of sealant and leakage through containment due to deterioration of joint seals gaskets, and moisture barriers	Containment ISI Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Concrete elements: foundation, dome, and wall (Item Number 3.5.1.7)	Aging of accessible and inaccessible concrete areas due to leaching of calcium hydroxide, aggressive chemical attack, and corrosion of embedded steel	Containment ISI Program	N/A	Not applicable BFN has a Mark I steel containment
Concrete elements: foundation (Item Number 3.5.1.8)	Cracks, distortion, and increases in components stress level due to settlement	Structures Monitoring Program	N/A	Not applicable BFN has a Mark I steel containment

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Concrete elements: foundation (Item Number 3.5.1.9)	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring Program	N/A	Not applicable BFN has a Mark I steel containment
Concrete elements: foundation, dome, and wall (Item Number 3.5.1.10)	Reduction of strength and modulus due to elevated temperature)	Plant-specific	N/A	Not applicable BFN has a Mark I steel containment
Prestressed containment: tendons and anchorage components (Item Number 3.5.1.11)	Loss of prestress due to relaxation, shrinkage, creep, and elevated temperature	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA	Not applicable BFN has a Mark I steel containment and not prestressed concrete with tendons
Steel elements: liner plate, containment shell (Item Number 3.5.1.12)	Loss of material due to corrosion in accessible and inaccessible areas	Containment ISI Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL which recommends further evaluation (See Section 3.5.2.1)
Steel elements: vent header, drywell head, torus, downcomers, and pool sheel (Item Number 3.5.1.13)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.6, Primary Containment Fatigue
Steel elements: protected by coating (Item Number 3.5.1.14)	Loss of material due to corrosion in accessible areas only	Protective Coating Monitoring and Maintenance Program	N/A	Not applicable BFN does not credit coatings to prevent general corrosion
Prestressed containment: tendons and anchorage components (Item Number 3.5.1.15)	Loss of material due to corrosion of prestressing tendons and anchorage components	Containment ISI Program	N/A	Not applicable BFN has a Mark I steel containment and not prestressed concrete with tendons
Concrete elements: foundation, dome, and wall (Item Number 3.5.1.16)	Scaling, cracking, and spalling due to freeze-thaw; expansion and cracking due to reaction with aggregate	Containment ISI Program	N/A	Not applicable BFN has a Mark I steel containment

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Steel elements: vent line bellows, vent headers, and downcomers (Item Number 3.5.1.17)	Cracking due to cyclic loads; crack initiation and growth due to SCC	Containment ISI Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL, which recommends further evaluation (See 3.5.2.1)
Steel elements: suppression chamber liner (Item Number 3.5.1.18)	Crack initiation and growth due to SCC	Containment ISI Program; Containment Leak Rate Test Program	Containment ISI Program; Containment Leak Rate Test Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.5.2.1)
Steel elements: drywell head and downcomer pipes (Item Number 3.5.1.19)	Fretting and lock up due to wear	Containment ISI Program	Containment ISI Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.5.2.1)
All Groups except Group 6: accessible interior/exterior concrete and steel components (Item Number 3.5.1.20)	All types of aging effects	Structures Monitoring Program	Structures Monitoring Program	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.1)
Groups 1-3, 5, 7-9: inaccessible concrete components, such as exterior walls below grade and foundation (Item Number 3.5.1.21)	Aging of inaccessible concrete areas due to aggressive chemical attack, and corrosion of embedded steel	Plant-specific		Consistent with GALL, which recommends further evaluation if an aggressive below-grade environment exists (See Section 3.5.2.2.1)
Group 6: all accessible/ inaccessible concrete, steel, and earthen components (Item Number 3.5.1.22)	All types of aging effects, including loss of material due to abrasion, cavitation, and corrosion	Inspection of Water-Control Structures; FERC/US Army Corps of Engineers Dam Inspection and Maintenance Program	Inspection of Water-Control Structures; FERC/US Army Corps of Engineers Dam Inspection and Maintenance Program	Consistent with GALL which recommends further evaluation (See Section 3.5.2.2.8)
Group 5: liners (Item Number 3.5.1.23)	Crack initiation and growth due to SCC; loss of material due to crevice corrosion	Chemistry Control Program; Monitoring of Spent Fuel Pool Water Level Program	Chemistry Control Program; Monitoring of Spent Fuel Pool Water Level Program	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.5.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Groups 1-3, 5, 6: all masonry block walls (Item Number 3.5.1.24)	Cracking due to restraint, shrinkage, creep, and aggressive environment	Masonry Wall Program	Masonry Wall Program	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Groups 1-3, 5, 7-9: foundation (Item Number 3.5.1.25)	Cracks, distortion, and increases in component stress level due to settlement	Structures Monitoring Program	Structures Monitoring Program	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.2)
Groups 1-3, 5-9: foundation (Item Number 3.5.1.26)	Reduction in foundation strength due to erosion of porous concrete subfoundation	Structures Monitoring Program	N/A	Not applicable BFN does not use porous concrete subfoundations
Groups 1-5: concrete (Item Number 3.5.1.27)	Reduction of strength and modulus due to elevated temperature	Plant-specific	Structures Monitoring Program	Consistent with GALL, which recommends further evaluation (See Section 3.5.2.2.3)
Groups 4, 8: liners (Item Number 3.5.1.28)	Crack initiation and growth due to SCC; loss of material due to crevice corrosion	Plant-specific	N/A	Not applicable BFN does not have any Group 7 structues BFN does not have in-scope stainless steel liners in an exposed-to-fluid environment for any Group 8 structure
All groups: support members, anchor bolts, concrete surrounding anchor bolts, welds, grout pad, bolted connections, etc. (Item Number 3.5.1.29)	Aging of component supports	Structures Monitoring Program	Structures Monitoring Program	Consistent with GALL, which recommends no further evaluation if within the scope of the applicant's Structures Monitoring Program (See Section 3.5.2.1)
Groups B1.1, B1.2, and B1.3: support members, anchor bolts, and welds (Item Number 3.5.1.30)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.6, Primary Containment Fatigue

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Groups B1.1, B1.2, and B1.3: support members, anchor bolts, welds, spring hangers, guides, stops, and vibration isolators (Item Number 3.5.1.32)	Loss of material due to environmental corrosion; loss of mechanical function due to corrosion, distortion, dirt, overload, etc.	ISI Program	ISI Program	Consistent with GALL, which recommends no further evaluation (See Section 3.5.2.1)
Group B1.1: high-strength low-alloy bolts (Item Number 3.5.1.33)	Crack initiation and growth due to SCC	Bolting integrity Program		Exception to GALL (See Section 3.5.2.3.26)

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.5.2.1, involves the staff's review of the AMR results for components in the containments, structures, and component supports that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.5.2.2, involves the staff's review of the AMR results for components in the containments, structures, and component supports that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.5.2.3, involves the staff's review of the AMR results for components in the containments, structures, and component supports that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the containments, structures, and component supports components is documented in SER Section 3.0.3.

3.5.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Not Recommended

<u>Summary of Technical Information in the Application</u>. In LRA Section 3.5.2.1, the applicant identified the materials, environments, and aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the containments, structures, and component supports components:

- 10 CFR 50 Appendix J Program
- ASME Section XI Subsection IWE Program
- Structures Monitoring Program
- Chemistry Control Program
- Fire Protection Program
- Masonry Wall Program
- Inspection of Water-Control Structures Program
- ASME Section XI Subsection IWF Program
- One-Time Inspection Program

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant has claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated that the AMR was consistent with the GALL Report.

Note A indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated that the component for the AMR line item is different from but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant had not been able to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated that the component for the AMR line item is different from but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component was applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant is consistent with the AMP identified in the GALL Report and whether the AMR is valid for the site-specific conditions.

Note E indicated that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR is valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA, as documented in the BFN audit and review report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL Report AMRs. The staff's evaluation is discussed below.

For aging management evaluations that the applicant stated are consistent with the GALL Report and for which further evaluation is not recommended, the staff conducted its review and audit to determine if the applicant's reference to the GALL Report in the LRA is acceptable.

The staff determined that the applicant had: (1) provided a brief description of the system, components, materials, and environment; (2) stated that the applicable aging effects have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the SCs that are subject to an AMR. The staff also determined that the LRA line item is consistent with the GALL Report Volume 2 system tables line item for component type and MEAP.

To confirm consistency with the GALL Report, during the onsite audit in the weeks of June 21 and July 26, 2004, the staff requested the applicant to clarify the following LRA line items:

In LRA Table 3.5.2.1, the applicant credits the 10 CFR Part 50, Appendix J Program for some structures and component supports in the primary containment. The GALL Report is also based on an expectation that plant technical specifications will be credited. The staff requested the applicant to identify these items and explain the BFN plant technical specifications that govern the leakage testing of these items after each opening.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.1, rows 4 and 6 apply to the drywell personnel access airlock. Table 3.5.2.1, rows 8 and 10, apply to the torus and drywell access hatches and equipment hatches. These containment pressure boundary components will continue to be inspected consistent with the CLB Technical Specifications for Appendix J requirements. BFN Technical Specification Requirements, Section 5.5.12, "Primary Containment Leakage Rate Testing Program," provides the requirement to establish a program to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, and provides the leakage rate acceptance criteria of the program. With these clarifications, the staff concluded that these items are consistent with the GALL Report.

In reference to LRA Table 3.5.2.1, the staff further requested the applicant to identify the caulking and sealants included under this item and clarify why Appendix J is not a credited AMP. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.1 applies to the moisture barrier seal between the drywell steel shell and the concrete floor in the bottom of the drywell, elevation 549.92 feet. Appendix J testing is not required, since the drywell floor moisture barrier seal between drywell steel shell and the 549.92-foot elevation concrete does not have a pressure boundary function. The staff concurred with the applicant's explanation and found this acceptable.

In LRA Table 3.5.2.2, the staff observed that the AMP referenced for spent fuel pool liners is not consistent with GALL Report Item III.A5.2-b. The Chemistry Control Program is referenced. However, the GALL Report also includes "monitoring of the spent fuel pool level." The staff requested that the applicant provide the technical basis for this omission. By letter dated

October 8, 2004, the applicant submitted its formal response to the staff, stating that the AMP section for LRA Table 3.5.2.2 should have identified that the spent fuel pool level is monitored by plant operations. Browns Ferry will submit a change to correct this omission. With this correction, the staff concluded that the applicant's AMR is consistent with the GALL Report.

In reference to LRA Table 3.5.2.2, the staff also requested the applicant to describe the AMR for Boral and to clarify whether stainless steel components are used to support the Boral. If the AMR supports the conclusion that Boral does not require aging management, but the stainless steel supports do, then the Chemistry Control Program would be an acceptable AMP for this item. If not, the applicant was requested to provide the technical basis for crediting the Chemistry Control Program as the appropriate AMP for Boral.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the Boral core is made up of a central segment of a dispersion of boron carbide in aluminum. This central segment is clad on both sides with aluminum to form a plate. The Boral plates are sandwiched between two stainless steel plates which are closure-welded form the container. Vent holes have been added to prevent the buildup of hydrogen gas between the stainless steel containers. If the stainless steel containers remain intact, the Boral core will be unaffected and will retain its neutron-absorbing capacity. The Chemistry Control Program will manage aging of the stainless steel containers. With these clarifications, the staff concluded that this item is consistent with the GALL Report.

In reference to LRA Tables 3.5.2.12, 3.5.2.13, and 3.5.2.26, the staff requested that the applicant identify each of the components included and explain the reference to Note C (Component is different from, but consistent with, GALL Report item for material, environment, and aging effect. The AMP is consistent with the GALL Report).

In its response, by letter dated October 8, 2004, the applicant stated that Table 3.5.2.1.12, rows 41 and 42, apply to security barrier steel framing at the intake pumping station. Note C was used because the security barrier steel framing was evaluated with structural steel beams columns, and trusses (steel components) commodity group. Table 3.5.2.13, rows 4, 5, 6, 7, and 8, apply to concrete that is sandwiched between the steel sheet pile cells of Gate Structure Number 3. Note C was used because the concrete sandwiched between the steel sheet pile cells was evaluated with concrete elements that were not sandwiched between steel sheet piles. Table 3.5.2.26, rows 19 and 20, apply to cable trays and supports in containment atmosphere and inside air environments. Note C was used because cable trays were evaluated with the cable tray supports. With these clarifications, the staff concluded that these items are consistent with the GALL Report.

In reference to LRA Table 3.5.2.12, the staff requested the applicant to explain the extent to which the referenced submerged structures are inspected for the effects of freeze-thaw under the Inspection of Water-Control Structures Program. By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the referenced submerged structure will be inspected for the effects of freeze-thaw at the waterline where icing conditions could occur. The staff concluded that the applicant's approach to the management of this aging effect is consistent with the GALL Report.

On the basis of its audit, the staff determined that, for AMRs not requiring further evaluation, as identified in LRA Table 3.5.1 (Table 1), the applicant's references to the GALL Report are acceptable, that the line items are consistent with the GALL Report, and no further staff review is required.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concluded that the AMR results, that the applicant claimed to be consistent with the GALL Report are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR54.21(a)(3).

3.5.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.5.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the containments, structures, and component supports. The applicant provided information concerning how it will manage the following aging effects:

- aging of inaccessible concrete areas
- cracking, distortion, and increase in component stress level due to settlement; reduction of foundation strength due to erosion of porous concrete subfoundations, if not covered by Structures Monitoring Program
- reduction of strength and modulus of concrete structures due to elevated temperature
- loss of material due to corrosion in inaccessible areas of steel containment shell or liner plate
- loss of prestress due to relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking due to cyclic loading and stress corrosion cracking
- aging of structures not covered by Structures Monitoring Program
- aging management of inaccessible areas
- aging of supports not covered by Structures Monitoring Program
- cumulative fatigue damage due to cyclic loading
- quality assurance for aging management of non-safety-related components

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it had adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.5.2.2. Details of the staff's audit are documented in the staff's BFN audit and review report. The staff's evaluation of the aging effects is discussed in the following sections.

3.5.2.2.1 Aging of Inaccessible Concrete Areas

The discussion in SRP-LR Section 3.5.2.2.1.1 is not applicable to BFN since BFN is a BWR with a Mark I steel containment.

3.5.2.2.2 Cracking, Distortion, and Increase in Component Stress Level Due to Settlement; Reduction of Foundation Strength due to Erosion of Porous Concrete Subfoundations, if Not Covered by Structures Monitoring Program

The discussion in SRP-LR Section 3.5.2.2.1.2 is not applicable to BFN since BFN is a BWR with a Mark I steel containment.

3.5.2.2.3 Reduction of Strength and Modulus of Concrete Structures due to Elevated Temperature

The discussion in SRP-LR Section 3.5.2.2.1.3 is not applicable to BFN since BFN is a BWR with a Mark steel containment.

3.5.2.2.4 Loss of Material due to Corrosion in Inaccessible Areas of Steel Containment Shell or Liner Plate

The staff reviewed LRA Section 3.5.2.2.1.4 against the criteria in SRP-LR Section 3.5.2.2.1.4. In LRA Section 3.5.2.2.1.4, the applicant addressed loss of material due to corrosion in inaccessible areas of steel containment elements.

SRP-LR Section 3.5.2.2.1.4 states that loss of material due to corrosion could occur in inaccessible areas of the steel containment shell or the steel liner plate for all types of PWR and BWR containments. The GALL Report recommends further evaluation of plant-specific programs to manage this aging effect for inaccessible areas if the following specific criteria defined in the GALL Report cannot be satisfied: (1) concrete meeting the requirements of ACI 318 or 349 and the guidance of 201.2R was used for the containment concrete in contact with the embedded containment shell or liner; (2) the accessible concrete is monitored to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment shell or liner; (3) the accessible portion of the moisture barrier, at the junction where the shell or liner becomes embedded, is subject to aging management activities in accordance with IWE requirements; (4) borated water spills and water ponding on the containment concrete floor are not common and when detected are cleaned up in a timely manner.

In the LRA, the applicant stated that loss of material due to corrosion in inaccessible areas of steel containment elements is not significant. The drywell steel containment vessel is inaccessible (except for the drywell head) for visual examination from the outside surface. There has been evidence of water leaking from the sand bed drains on both Units 2 and 3. Since there is a horizontal weld connecting the first and second course of drywell liner plates approximately eight inches above the drywell concrete floor, ultrasonic testing (UT) thickness measurements from the drywell floor up to this weld, around the drywell circumference, would conservatively bound the sand pocket area. UT thickness measurements of this area were obtained during the U2C10 and U3C8 refueling outages for Units 2 and 3 respectively and in

1999 and 2002 for Unit 1. The data indicated that the condition of the drywell steel liner plate in this area is good and that this area did not require augmented examination.

The applicant further stated in the LRA that concrete structures and concrete components are designed in accordance with ACI 318-63 and ACI 318-71 and constructed using materials conforming to ACI and ASTM standards. The Structures Monitoring Program monitors the concrete to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment shell. Research of plant history did not reveal any instances of borated water spills or water ponding on the containment concrete floor. A general visual inspection of the moisture barrier at the junction of the steel drywell shell and the concrete floor is performed once each inspection interval in accordance with the ASME Code Section XI, Subsection IWE Program.

The applicant concluded in the LRA that, since all of the GALL Report further evaluation conditions are satisfied, a plant-specific AMP for corrosion in inaccessible areas (embedded containment steel shell and drywell support skirt) is not required.

During the audit, the staff requested the applicant to provide details of the UT measurements in the sand pocket region for all three units, including comparisons with the original wall thicknesses and trending results. The staff also requested the applicant to discuss future planned inspections of steel containment corrosion in the sand pocket region for all three units and the basis for not inspecting other regions of the drywell for all three units in light of the evidence of water leaking from the sand bed drains. It is noted that there is expansion foam in the air gap between the drywell shell and the surrounding concrete that can become wet as a result of the leaking water. Thus, other areas of the drywell shell could be susceptible to corrosion.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that in response to GL 87-05, which addressed the potential for corrosion of BWR Mark I steel drywells in the "sand pocket region," it had provided the staff with the results of the ultrasonic testing for corrosion degradation of drywell liner plate on Aug. 30, 1988. The results of the ultrasonic testing show that each unit's drywell had been ultrasonically tested near the sand cushion area during 1987. The tests showed that the nominal thickness was maintained on each drywell. Below, are the results of each unit's drywell ultrasonic testing. (Note: the following results are quoted from the applicant's letter to the staff dated August 30, 1988.)

- Unit 1- No reading below the nominal thickness of one inch was measured, indicating that the integrity of the drywell liner plate is maintained. Periodic leakage from the sand cushion area has been observed. Corrosive species in the drainage are bases to suspect a higher rate of corrosion on Unit 1 drywell liner plate than on Unit 2 and 3. However, objective evidence of serious corrosion damage was not noted.
- Unit 2 - No reading below the nominal thickness of one inch was measured, indicating that no damage to the integrity of the drywell liner plate has occurred.
- Unit 3 - No reading below the nominal thickness of one inch was measured, indicating that no damage to the integrity of the drywell liner plate has occurred.

The applicant further stated that Procedure SPP-9.1, "ASME Section XI," is the applicant's standard to establish administrative controls and provide requirements, standard methods, guidance, and interfaces for preparation of ASME Code Section XI and augmented inservice inspection and testing programs at each nuclear site. In addition, this procedure allows for the control and dissemination of the site programs as stand alone documents, as it is required to meet the individual site-specific requirements resulting from the physical plant differences. BFN Technical Instruction 0-TI-376, "ASME Section XI Containment Inservice Inspection Program Units 1, 2, and 3," is an administrative technical instruction employed to implement the inservice inspection provisions of SPP-9.1 relative to Class MC components at BFN. Appendix 9.7 to BFN Technical Instruction 0-TI-376 documents the Units 2 and 3 evaluation of Class MC components to determine augmented examination requirements in accordance with Table IWE-2500-1, Category E-C, Containment Surfaces Requiring Augmented Examination. Included as one of the areas to evaluate for augmented inspections was the "Drywell SCV at the sand bed region." The evaluation considered the potential degradation mechanisms of each area; the adequacy of existing programs and maintenance practices with respect to the monitoring, prevention, and correction of degradation; and industry experience applicable to the area; and provided a conclusion with respect to augmented examination requirements.

The applicant also stated that the drywell SCV at the sand bed region evaluation summarized the response to GL 87-05 and the need to obtain more data to conclude whether augmented inspections were warranted. UT thickness measurements of this area, in accordance with IWE-2500 (c)(2), (c)(3), and (c)(4), were obtained during the U3C8 and U2C10 refueling outages. The data indicate that the condition of the drywell steel liner plate in this area is good, and that this area should not be categorized for augmented examination for Units 2 and 3.

As part of the re-start activities for Unit 1, the applicant stated that a similar evaluation will be performed to determine if augmented inspections would be required. This evaluation and conclusion will be included in BFN Technical Instruction 0-TI-376 prior to Unit 1 re-start.

In its response, the applicant also noted that aging management of drywell corrosion will be addressed in its response to RAI 3.5-4. This issue is dispositioned in the staff evaluation of the applicant's response to RAI 3.5-4.

3.5.2.2.5 Loss of Prestress due to Relaxation, Shrinkage, Creep, and Elevated Temperature

The discussion in SRP-LR Section 3.5.2.2.1.5 is not applicable to BFN since BFN is a BWR with a Mark I steel containment.

3.5.2.2.6 Cumulative Fatigue Damage

In LRA Section 3.5.2.2.1.6, the applicant stated that fatigue analysis of BWR Mark I and Mark II containment steel elements, penetration sleeves, and penetration bellows are TLAAs as defined in 10 CFR 54.3. The TLAA evaluation of cumulative fatigue damage is addressed in LRA Section 4.6. The staff evaluated TLAAs in SER Section 4.

3.5.2.2.7 Cracking due to Cyclic Loading and Stress Corrosion Cracking

The staff reviewed LRA Section 3.5.2.2.1.7 against the criteria in SRP-LR Section 3.5.2.2.1.7.

In LRA Section 3.5.2.2.1.7, the applicant addressed aging mechanisms that can lead to cracking of penetration sleeves and penetration bellows such as cyclic loads and SCC.

SRP-LR Section 3.5.2.2.1.7 states that cracking of containment penetrations (including penetration sleeves, penetration bellows, and dissimilar metal welds) due to cyclic loading or SCC could occur in all types of containments. Cracking could also occur in vent line bellows, vent headers and downcomers due to SCC for BWR containments. Further evaluation of inspection methods is recommended to detect cracking due to cyclic loading and SCC since visual VT-3 examinations may be unable to detect this aging effect.

Cracking Due to SCC. The GALL AMP XI.S1, "ASME Section XI Subsection IWE," covers inspection of these items under examination categories E-B, E-F, and E-P (10 CFR Part 50 Appendix J pressure tests). In 10 CFR 50.55a, examination categories E-B and E-F are identified as optional during the current term of operation. For the extended period of operation, examination categories E-B and E-F, and additional appropriate examinations to detect SCC in bellows assemblies and dissimilar metal welds, are warranted to address this issue.

In the LRA, the applicant stated that SCC of stainless steel exposed to atmospheric conditions and contaminants is considered plausible only if the material temperature is above 140 °F. In general, SCC very rarely occurs in austenitic stainless steels below 140 °F. Although stress corrosion cracking has been observed in systems at temperatures lower than this 140 °F threshold, all of these instances have identified a significant presence of contaminants (halogens, specifically chlorides) in the failed components. This material is at a relatively low temperature, in a sheltered environment, and not exposed to a corrosive environment.

The applicant further stated in the LRA that industry experience, detailed in NRC information notice (IN) 92-20, described instances of the failure of the 10 CFR Part 50 Appendix J local leak rate test (LLRT) to detect cracking in stainless steel containment penetration bellows. The LLRT was inadequate due to the type of penetration bellows utilized at the nuclear power plant that is the subject of the IN. The type of bellows used on the containment penetrations at BFN is not the type described in IN 92-20. The vent line bellows are a single-ply bellows design. Pipe penetration bellows for high-energy lines are two-ply bellows with a mesh. The design of the penetration bellows allows full pressure to be transmitted to all portions of the bellows during Appendix J testing. Containment penetrations bellows are not susceptible to failure of the 10 CFR Part 50 Appendix J LLRT to detect cracking, as described in IN 92-20. A review of the operating history for the past five years did not indicate any failures associated with vent line and penetration bellows. This issue was pursued in staff RAI 3.5-1 (see SER Section 3.5.2.3.1)

The applicant also stated in the LRA that the reinstatement of Examination Categories E-B and E-F would result in hardship or unusual difficulty for BFN without a compensating increase in the level of quality and safety. Therefore, existing requirements for 10 CFR Part 50 Appendix J Program leak rate testing and visual examinations, in accordance with ASME Code Section XI, Subsection IWE, Examination Category E-A, should be adequate to detect cracking due to SCC. The reinstatement of ASME Code Section XI, Subsection IWE, Weld Examination Categories E-B and E-F would not be required. Weld Examination Categories E-B and E-F have been removed from the ASME Code Section XI, 1998 Edition.

During the audit, the staff asked the applicant if there was any operating history at BFN beyond the past five years regarding signs of cracking and/or failures associated with the vent line and penetration bellows. The staff also requested the applicant to discuss the hardship or unusual difficulty for the applicant regarding reinstatement of Examination Categories E-B and E-F.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that during the last nine years there has been no operating experience to indicate that cracking or other aging effects resulted in a loss of intended function of the vent line bellows or penetration bellows.

The applicant further stated that, in accordance with 10 CFR 50.55a, the performance of examinations required by examination categories E-B and E-F are optional and that the staff found no evidence of industry problems with these welds.

The applicant also stated that specific weld locations on the containment would be required to be located and identified on weld maps in order to perform examinations for examination categories E-B and E-F. These weld locations have not been identified for the ASME Code Section XI Subsection IWE ISI Program. The hardship associated with performing the weld examinations associated with examination categories E-B and E-F is attributed to radiation exposure received while performing examinations of welds that have no industry experience of problems. Since specific weld locations have not been identified for the ASME Code Section XI Subsection IWE ISI Program, it is not possible to provide an estimated radiation exposure for performance of the examinations.

The applicant's response also noted that the Summary of SECY-96-080, "Issuance Of Final Amendment To 10 CFR 50.55a To Incorporate By Reference The ASME Boiler And Pressure Vessel Code (ASME Code), Section XI, Division 1, Subsection IWE And Subsection IWL," states the following:

> The third modification, 50.55a(b)(2)(x)(C), makes the Subsection IWE pressure retaining welds and Subsection IWE pressure retaining dissimilar metal welds inspection optional. The staff concluded that requiring these inspections is not appropriate. There is no evidence of problems associated with welds of this type in operating plants. Therefore, the occupational radiation exposure that would be incurred while performing these inspections cannot be justified. It is estimated that the total occupational exposure that would be incurred yearly in the performance of the containment weld inspections would be 440 person-rems.

The staff found the applicant's response to be acceptable.

Cracking Due to Cyclic Loading. Cracking of the containment shell and penetrations due to cyclic loading is a TLAA. The staff evaluated TLAAs in SER Section 4.

3.5.2.2.8 Aging of Structures Not Covered by Structures Monitoring Program

The staff reviewed LRA Section 3.5.2.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.2.1. LRA Section 3.5.2.2.2.1 addresses aging of Class 1 structures not covered by the Structures Monitoring Program.

SRP-LR Section 3.5.2.2.2.1 states that the GALL Report recommends further evaluation of certain structure/aging effect combinations if they are not covered by the Structures Monitoring Program. This is described in GALL Report Chapter III and includes: (1) scaling, cracking, and spalling due to repeated freeze-thaw for Groups 1-3, 5, 7-9 structures; (2) scaling, cracking, spalling and increases in porosity and permeability due to leaching of calcium hydroxide and aggressive chemical attack for Groups 1-5, 7-9 structures; (3) expansion and cracking due to reaction with aggregates for Groups 1-5, 7-9 structures; (4) cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel for Groups 1-5, 7-9 structures; (5) cracks, distortion, and increase in component stress level due to settlement for Groups 1-3, 5, 7-9 structures; (6) reduction of foundation strength due to erosion of porous concrete subfoundations for Groups 1-3, 5-9 structures; (7) loss of material due to corrosion of structural steel components for Groups 1-5, 7-8 structures; (8) loss of strength and modulus of concrete structures due to elevated temperatures for Groups 1-5; and (9) crack initiation and growth due to SCC and loss of material due to crevice corrosion of stainless steel liner for Groups 7 and 8 structures. Further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

SRP-LR Section 3.5.2.2.2.1 references SRP-LR Subsection 3.5.2.2.1.2 for the technical details of the aging management issue for Items (5) and (6), above, and references SRP-LR Section 3.5.2.2.1.3 for the technical details of the aging management issue for Item (8), above.

In LRA Section 3.5.2.2.2.1, the applicant stated that the further evaluations are also applied to Group 6 structures, when applicable; and that the technical details of the AMRs associated with SRP-LR Section 3.5.2.2.1.2, "Cracking, Distortion, and Increase in Components Stress Level due to Settlement; Reduction of Foundation Strength due to Erosion of Porous Concrete Subfoundations, if Not Covered by Structures Monitoring Program," and SRP-LR Section 3.5.2.2.1.3, "Reduction of Strength and Modulus of Elasticity due to Elevated Temperature," are also incorporated in this further evaluation.

The staff's evaluation for Items (1) through (9) is presented below:

(1) Freeze-thaw

The GALL Report, as updated by ISG-3, recommends that for accessible areas inspections performed in accordance with the Structures Monitoring Program will indicate the presence of loss of material (spalling, scaling) and cracking due to freeze-thaw. For inaccessible areas, evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557). Documented evidence to confirm that the in-place concrete had the air content of three to six percent and that subsequent inspections performed did not detect degradation related to freeze-thaw should be considered a part of the evaluation. The weathering index for the continental US is shown in ASTM C33-90, Figure 1.

In LRA Section 3.5.2.2.2.1, the applicant stated that BFN is located in an area with moderate weathering conditions, as noted on Figure 1 of ASTM C33-99. Freeze-thaw is not considered an aging mechanism for concrete components below the frost line. The concrete structures and concrete are designed in accordance with ACI 318-63 and ACI 318-71 and constructed using ingredients conforming to ACI and ASTM standards. TVA specifications require all concrete to contain an air-entraining agent in sufficient quantity to maintain specified percentages based on nominal maximum size aggregate. For severe weather exposures (as defined in TVA-Specifications), the air content identified varies from 4 to 10 percent, depending on aggregate size. Severe weather exposure (as described in TVA-Specifications), is defined as "all exterior surfaces of concrete which will be exposed to alternate wetting and drying."

The applicant further stated in the LRA that specified air content for reinforced concrete is greater than the three to six percent for air content identified in ISG-03. Therefore, loss of material (spalling, scaling) and cracking due to freeze-thaw are aging effects that require aging management in accordance with ISG-03 for below-grade (above the frost line) reinforced concrete structures and components. Below-grade reinforced concrete will be inspected by the Structures Monitoring Program when excavated for any reason. Accessible exterior above-grade concrete will be monitored by the Structures Monitoring Program to manage loss of material and cracking due to freeze-thaw.

The staff concluded that the applicant's AMR for loss of material and cracking due to freeze-thaw is consistent with the GALL Report, and that the aging effects will be adequately managed by the Structures Monitoring Program.

(2)(a) Leaching of Calcium Hydroxide

The GALL Report, as updated by ISG-3, recommends that for accessible areas inspections performed in accordance with the Structures Monitoring Program will indicate the presence of increase in porosity and permeability due to leaching of calcium hydroxide. For inaccessible areas, a plant-specific AMP is required for below-grade inaccessible areas (basemat and concrete wall) if the concrete is exposed to flowing water (NUREG-1557). An AMP is not required, even if reinforced concrete is exposed to flowing water, if there is documented evidence that confirms the in-place concrete was constructed in accordance with the recommendations in ACI 201.2R-77.

In LRA Section 3.5.2.2.2.1, the applicant stated that concrete structures and concrete components are designed in accordance with ACI 318-63 and ACI 318-71 and constructed using ingredients conforming to ACI and ASTM standards, which provide for a good quality, dense, well cured, and low permeability concrete. Cracking is controlled through proper arrangement and distribution of reinforcing steel. Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio which is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77. In addition, concrete components must be exposed to flowing water through the concrete component. Leaching of calcium hydroxide is readily noticeable as white deposits that remain on the concrete surface after a solution of water-free lime from the concrete and carbon dioxide from the air is absorbed and dries. The Structures Monitoring Program inspects concrete areas for signs of leaching. No significant signs of leaching have been documented during these inspection walkdowns. Therefore, the conditions identified in the GALL Report as revised by ISG-03 are satisfied, and aging management of an increase in porosity and permeability and a loss of strength due to leaching of calcium hydroxide for below-grade inaccessible concrete is not required. However, the Structures Monitoring Program will be used to manage aging effects caused by an increase in porosity and permeability and loss of strength due to leaching of calcium hydroxide of concrete.

The staff concluded that the applicant's AMR for scaling, cracking, spalling and increase in porosity and permeability due to leaching of calcium hydroxide is consistent with the GALL Report, and that the aging effects will be adequately managed by the Structures Monitoring Program.

(2)(b) Aggressive Chemical Attack

The GALL Report, as updated by ISG-3, recommends that for accessible areas, inspections performed in accordance with the Structures Monitoring Program will indicate the presence of increase in porosity and permeability, cracking, or loss of material (spalling, scaling) due to aggressive chemical attack. For inaccessible areas, a plant-specific AMP is required (may be a part of Structures Monitoring Program) if the below-grade environment is aggressive (pH < 5.5; chlorides >500 ppm; or sulfates >1500 ppm). Examination of representative samples of below-grade concrete, when excavated for any reason, is to be included as part of a plant-specific program. The GALL Report notes that periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is nonaggressive.

In LRA Section 3.5.2.2.2.1, the applicant stated that the Structures Monitoring Program will be used to inspect accessible concrete areas for aging effects caused by scaling, cracking, spalling and increase in porosity and permeability due to aggressive chemical attack.

The staff concluded that the applicant's AMR for scaling, cracking, spalling and increase in porosity and permeability due to aggressive chemical attack is consistent with the GALL Report for accessible areas, and that the aging effects will be adequately managed by the Structures Monitoring Program. The staff's evaluation for inaccessible areas is in SER Section 3.5.2.2.9.

(3) Reaction with Aggregates

The GALL Report, as updated by ISG-3, recommends that for accessible areas, inspections/evaluations performed in accordance with the Structures Monitoring Program will indicate the presence of expansion and cracking due to reaction with aggregates. For inaccessible areas, evaluation is needed if investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295-54, ASTM C227-50, or ACI 201.2R-77 (NUREG-1557) demonstrate that the aggregates are reactive.

In LRA 3.5.2.2.2.1, the applicant stated that the aggregate used in the concrete of the BFN components did not come from a region known to yield aggregates suspected of, or known to cause, aggregate reactions. Materials for concrete used in BFN structures and components were specifically investigated, tested, and examined in accordance with pertinent ASTM standards. All aggregates used at BFN conform to the requirements of ASTM C33 "Standard Specification of Concrete Aggregates." Appendix XI of ASTM C33 identifies methods for evaluating potential reactivity of aggregates including ASTM C295, ASTM C289, ASTM C227, and ASTM C342. If potentially reactive aggregates were used, then use of a low alkali Portland Cement (ASTM C150 Type II) containing less than 0.60 percent alkali calculated as sodium oxide equivalent was required by TVA-Specifications and will prevent harmful expansion due to alkali aggregate reaction. Therefore, the conditions identified in the GALL Report as revised by ISG-03 are satisfied, and aging management of expansion and cracking due to reaction with aggregates for below-grade inaccessible concrete is not required. However, the Structures Monitoring Program will be used to inspect accessible concrete areas for aging effects caused by reaction with aggregates.

The staff concluded that the applicant's AMR for expansion and cracking due to reaction with aggregates is consistent with the GALL Report, and that the aging effects will be adequately managed by the Structures Monitoring Program.

(4) Corrosion of embedded steel

The GALL Report, as updated by ISG-3, recommends that for accessible areas, inspections performed in accordance with the Structures Monitoring Program will indicate the presence of cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel. For inaccessible areas, a plant-specific AMP is required (may be a part of Structures Monitoring Program) if the below-grade environment is aggressive (pH < 5.5, chlorides > 500ppm, or sulfates > 1500 ppm). Examination of representative samples of below-grade concrete, when excavated for any reason, is to be included as part of a plant-specific program. The GALL Report notes that periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is aggressive or nonaggressive.

In LRA 3.5.2.2.2.1, the applicant stated that BFN will use the Structures Monitoring Program to inspect accessible concrete areas for aging effects caused by corrosion of embedded steel.

The staff concluded that the applicant's AMR for cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel is consistent with the GALL Report for accessible areas, and that the aging effects will be adequately managed by the Structures Monitoring Program. The staff's evaluation for inaccessible areas is in SER Section 3.5.2.2.9.

(5) Settlement

SRP-LR Section 3.5.2.2.2.1 refers to SRP-LR Section 3.5.2.2.1.2 for discussion of settlement. SRP-LR Section 3.5.2.2.1.2 states that cracking, distortion, and increase in component stress level due to settlement could occur in Class I structures. Some plants may rely on a de-watering system to lower the site ground water level. If the plant's CLB credits a de-watering system, the GALL Report recommends verification of the continued functionality of the de-watering system during the period of extended operation. The GALL Report recommends no further evaluation if this activity is included in the scope of the applicant's Structures Monitoring Program.

In LRA Section 3.5.2.2.2.1, the applicant stated that cracks, distortion, and increase in component stress level due to settlement are not considered AERM for structures founded on rock or bearing piles. The following BFN structures are founded on rock or bearing piles: reactor buildings, primary containments, intake pumping station, reinforced concrete chimney, off-gas treatment building, equipment access lock, turbine buildings, gate structure number 3, diesel HPFP house, transformer yard, and RHRSW tunnel. Based on industry experience, settlement of Class I structures founded on bedrock or bearing piles have not been noted to cause AERM.

For concrete structures founded on dense soil or backfill, the applicant stated that it can be concluded that cracking due to settlement is not significant if in the past 20 years of operating experience for a structure the total differential settlement experienced is well within the permissible limits for this type of structure and no settlement has manifested itself via cracked walls or cracked foundations. In this case, aging management for settlement would not be applicable for the structure during the period of extended operation. Prior settlement monitoring programs have revealed that soil settlement has stabilized and the structures will continue to perform their intended functions. However, due to prior operating history of settlement in the 1980s at BFN, cracking and distortion due to settlement of structures founded on soil or backfill will be monitored by the Structures Monitoring Program.

The staff concluded that the applicant's AMR for cracks, distortion, and increase in component stress level due to settlement is consistent with the GALL Report, and that the aging effects will be adequately managed by the Structures Monitoring Program.

(6) Erosion of porous concrete subfoundation

The GALL Report states that erosion of cement from porous concrete subfoundations beneath containment basemats is described in IN 97-11. IN 98-26 proposes Maintenance Rule structures monitoring for managing this aging effect, if applicable. If a dewatering system is relied upon for control of erosion of cement from porous concrete subfoundations, then the applicant is to ensure proper functioning of the dewatering system through the period of extended operation.

In LRA 3.5.2.2.2.1, the applicant stated that the evaluation of Information Notice 98-26 concluded that porous concrete subfoundations were not used at BFN. A dewatering system is not relied upon for control of erosion of cement from porous concrete subfoundations. Therefore, reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation are not applicable.

The staff concluded that the applicant's AMR for reduction in foundation strength, cracking, and differential settlement due to erosion of porous concrete subfoundation is consistent with the GALL Report, and that these aging effects are not applicable.

(7) Corrosion of structural steel components

The GALL Report states that further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program. If protective coatings are relied upon to manage the effects of aging, the Structures Monitoring Program is to include requirements to address monitoring and maintenance of protective coatings.

In LRA Section 3.5.2.2.2.1, the applicant stated that the Structures Monitoring Program will manage loss of material due to corrosion of structural steel components. The Structures Monitoring Program procedures specify visual inspections of structural conditions as the method used to detect degradation.

The applicant further stated that, for the steel that is embedded/encased within the concrete, corrosion is not an applicable aging mechanism. The concrete must first be degraded by other aging mechanisms, which reduce the protective cover and allow for the intrusion of aggressive ions causing a reduction in concrete pH. Aging management of previously noted concrete aging effects will manage loss of material for steel that is embedded/encased within concrete.

The applicant also makes note that NUREG-1557, Table B9, states that steel piles driven in undisturbed soil have been unaffected by corrosion and those driven in disturbed soil experience minor to moderate corrosion to a small area of metal. Loss of material for steel piles driven in undisturbed or disturbed soil does not require aging management.

The applicant also stated that the protective coating monitoring and maintenance program is not credited for aging management of loss of material for structural steel components.

The staff concluded that the applicant's AMR for loss of material due to corrosion of structural steel components is consistent with the GALL Report, and that the aging effects will be adequately managed by the Structures Monitoring Program. The staff also concurred with the applicant's AMR for steel piles, because it is based on a documented staff technical assessment.

(8) Elevated temperatures

The GALL Report calls for a plant-specific AMP and recommends further evaluation if any portion of the concrete components exceeds specified temperature limits, (i.e., general area temperature 66 °C (150 °F) and local area temperature 93 °C (200 °F)).

In LRA Section 3.5.2.2.2.1, the applicant stated that with the exception of the main steam tunnels in the reactor building BFN reinforced concrete structures have general area temperatures less than 150 °F during normal operation. General area temperatures have been conservatively evaluated using maximum normal space ambient temperatures noted on the harsh environmental drawing series and associated calculations. The main steam tunnels have a maximum normal space ambient temperature of 160 °F, as noted in the harsh environmental drawing series and associated calculations. This is a maximum normal space ambient temperature. The harsh environmental drawing series and associated calculations identify the space average normal ambient temperature as 135 °F. This is judged to be acceptable by the applicant, because when concrete is subjected to prolonged exposure to elevated temperatures reductions in excess of 10 percent of the compressive strength, tensile strength, and the modulus of elasticity begin to occur in the range of 180 °F to 200 °F.

The applicant further stated that each drywell is cooled during normal plant operation by a closed-loop ventilation system designed to keep the average temperature in the drywell less than 150 °F. The general area temperature inside the drywell (primary containment) is maintained below 150 °F as required by Technical Specifications. Elevated temperatures on internal concrete components such as the reactor support pedestal, where the temperature could approach 150 °F, are addressed as appropriate by BFN civil design criteria. The drywell concrete structure surrounding the drywell vessel was evaluated for thermal effects from the general area temperature of the drywell. The upper elevations of the sacrificial shield wall may exceed 150 °F briefly and infrequently, during abnormal operations; this is not considered to affect its function.

The applicant concluded that the conditions identified in the GALL Report are satisfied and aging management for reduction of strength and modulus due to elevated temperature for concrete components is not required.

During the audit, the staff requested the applicant to:

(1) Explain how the elevated temperature on internal concrete components, where the temperature could approach 150 °F, are addressed by BFN civil design criteria.

(2) Discuss the evaluation of the drywell concrete structure for thermal effects.

(3) Discuss the technical basis for concluding that "the upper elevations of the sacrificial shield wall may exceed 150 °F briefly and infrequently, during abnormal operations and is not considered to affect its functions."

(4) Discuss the local temperatures that can be expected in the concrete surrounding hot piping penetrations and what provisions exist for maintaining these temperatures within acceptable limits.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the GDC document, BFN-50-C-7100 "Design of Civil Structures" (DC), provides the design basis requirements for all BFN structures, including the primary containment. In DC Section 3.2.5, Appendix C, the temperature requirements are defined for the drywell concrete, with an operating temperature of 150 °F specified for the drywell.

DC Appendix C, Table 15-10, "Reactor Support Pedestal Design Data," provides the principal design cases for the reactor support pedestal and includes the requirement to consider thermal effects for each principal design case. DC Appendix C, Table 15-12, "Reactor Building Concrete Structure Fuel Pool Storage Pool and Dryer/Separator Storage Pool Design Data," requires the consideration of drywell thermal rise for the appropriate principal design cases for the spent fuel storage pool and dryer/separator storage pool of the reactor building. Both these pools have structural elements that form portions of the outer structural concrete shell of the primary containment steel shell. DC Appendix C, Table 15-15(a), "Drywell Concrete Structure," provides the principal design cases for the drywell concrete and requires the consideration of thermal effects in the principal loading combinations for the drywell concrete structure.

The applicant further stated that the sacrificial shield wall provides a biological shield for protection of personnel from gamma radiation, a neutron shield to prevent activation of the drywell components during operation, and a means of supporting the drywell pipe hangers and access platform. It also provides protection against damage to the nuclear system process barrier due to seismic loading, against further damage due to vessel pipe penetration rupture jet forces, and a limit stop and support for pipe restraints in the event of a drywell pipe rupture. It consists of a 24-foot diameter circular cylinder attached to the vessel support pedestal and extending upward approximately 45 feet. The sacrificial shield wall is 27 inches thick and is constructed from 26-inch vertical WF beam columns, tied together by horizontal WF beams and 1/4-inch plates.

The applicant stated that the ¼-inch plates are welded to the column flanges, both inside and outside, thereby forming a double-walled shell. This shell is filled with concrete to provide biological shielding capability. The concrete was assumed to have no structural purpose, except for the lowest 10 feet 6 inches of the wall. Based on the design criterion that the concrete has no structural purpose except for the lowest 10.5 feet, the applicant concluded that "the upper elevations of the sacrificial shield wall may exceed the 150 °F briefly and infrequently during abnormal operation and is not considered to affect its function," as stated in LRA 3.5.2.2.2.1, Item 8.

In its response, the applicant also noted that degradation of drywell concrete due to elevated temperature would be addressed in its response to RAI 3.5-5. This issue will be dispositioned in the staff evaluation of the applicant's response to RAI 3.5-5.

(9) Aging Effects for Stainless Steel Liners for Tanks

In LRA Section 3.5.2.2.2.1, the applicant stated that BFN does not have any Group 7 structures or in-scope stainless steel liners in an exposed-to-fluid environment for any Group 8 structures. The staff concluded that further evaluation of this aging effect is not applicable.

In summary, the staff found that the applicant had demonstrated that the effects of aging, with the exception of elevated temperatures, will be adequately managed by the Structures Monitoring Program, 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).

3.5.2.2.9 Aging Management of Inaccessible Areas

The staff reviewed LRA Section 3.5.2.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2.2. In LRA Section 3.5.2.2.2.2, the applicant addressed aging of inaccessible areas of Class 1 structures.

SRP-LR Section 3.5.2.2.2.2 states that cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack; and cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel could occur in below-grade inaccessible concrete areas. The GALL Report recommends further evaluation to manage these aging effects in inaccessible areas of Groups 1-3, 5, 7-9 structures, if an aggressive below-grade environment exists. ISG-3 identifies additional requirements.

The GALL Report, as updated by ISG-3, states that for inaccessible areas, a plant-specific AMP is required (may be part of Structures Monitoring Program) if the below-grade environment is aggressive (pH < 5.5; chlorides > 500 ppm; or sulfates > 1500 ppm). Examination of representative samples of below-grade concrete, when excavated for any reason, is to be included as part of a plant-specific program. The GALL Report also notes that periodic monitoring of below-grade water chemistry (including consideration of potential seasonal variations) is an acceptable approach to demonstrate that the below-grade environment is nonaggressive.

In LRA Section 3.5.2.2.2.2, the applicant stated that design and construction of reinforced concrete provides dense, well cured, and low permeability concrete with an acceptable degree of protection for the embedded steel against exposure to an aggressive environment. Cracking of concrete is controlled through proper arrangement and distribution of reinforcing steel.

The applicant further stated that continued or frequent cyclic exposure to the following aggressive environments is necessary for aggressive chemicals to cause significant aggressive chemical attack or corrosion of embedded steel:

- acidic solutions with pH less than 5.5
- chloride solutions greater than 500 ppm
- sulfate solutions greater than 1500 ppm

The applicant stated that aggressive chemicals are present at plant sites, system leakage is leakage that could cause aggressive chemical attack is possible. However, leaks are not expected to continue for the extensive periods required for degradation, and repairs would be completed prior to loss of intended function. An aggressive environment may also occur where concrete is exposed to aggressive aqueous solutions such as groundwater or aggressive water flow. Groundwater sample measurements confirm that parameters are below threshold limits that could cause aggressive chemical attack for below-grade inaccessible concrete. Natural groundwater movement in this area is from the plant site to Wheeler Reservoir. Wheeler Reservoir water samples also confirm that an aggressive environment does not exist. Therefore, the applicant concludes that the conditions identified in the GALL Report, as revised by ISG-03, are satisfied and aging management of cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack; and cracking, spalling, loss of bond and loss of material due to corrosion of embedded steel is not required for below-grade inaccessible concrete.

The applicant concluded that Browns Ferry groundwater and Wheeler Reservoir sample measurements have confirmed that parameters are well below threshold limits that could cause concrete degradation (an aggressive environment does not exist) and that the rate of groundwater flow is not considered aggressive.

The applicant stated that BFN does not commit to periodic groundwater monitoring over the period of license extension, since it is not credible to postulate that some environmental event will occur in the future that would affect the quality of groundwater in the vicinity of Browns Ferry. A change in the environment due to a chemical release would be considered an abnormal event. SRP-LR states that aging effects from abnormal events need not be postulated specifically for license renewal.

The staff found that the applicant's response is not consistent with the GALL Report recommendation for periodic monitoring of groundwater. This issue was dispositioned by the staff, based on the applicant's responses to RAIs 3.5-7 and 3.5-8 and is discussed in SER Section 3.5.2.3.2.

3.5.2.2.10 Aging of Supports Not Covered by Structures Monitoring Program

The staff reviewed LRA Section 3.5.2.2.3.1 against the criteria in SRP-LR Section 3.5.2.2.3.1. In LRA Section 3.5.2.2.3.1, the applicant addressed aging of component supports that are not managed by the Structures Monitoring Program.

SRP-LR Section 3.5.2.2.3.1 states that the GALL Report recommends further evaluation of certain component support/aging effect combinations if they are not covered by the Structures Monitoring Program. This includes (1) reduction in concrete anchor capacity due to degradation of the surrounding concrete for Groups B1-B5 supports; (2) loss of material due to environmental corrosion for Groups B2-B5 supports; and (3) reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports. Further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

(1) Reduction in concrete anchor capacity due to degradation of the surrounding concrete for Groups B1 through B5 supports.

In LRA Section 3.5.2.2.3.1, the applicant stated that reduction in concrete anchor capacity due to local concrete degradation for Groups B1 – B5 supports will be managed by the Structures Monitoring Program.

(2) Loss of material due to environmental corrosion, for Groups B2-B5 supports.

In LRA Section 3.5.2.2.3.1, the applicant stated that loss of material due to environmental corrosion for Groups B2 – B5 Supports will be managed by the Structures Monitoring Program.

(3) Reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports.

In LRA Section 3.5.2.2.3.1, the applicant stated that there are no vibration elements within the scope of license renewal.

The staff found that the applicant had appropriately evaluated AMR results involving management of aging of component supports, as recommended in the GALL Report. The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.5.2.2.11 Cumulative Fatigue Damage due to Cyclic Loading

Cumulative fatigue damage is a TLAA. TLAAs are evaluated in SER Section 4.

3.5.2.2.12 Quality Assurance for Aging Management of Non-Safety-Related Components

SER Section 3.0.4 provides a separate evaluation of the applicant's Quality Assurance Program.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.5.2.3 AMR Results That Are Not Consistent with or Not Addressed in the GALL Report

Summary of Technical Information in the Application. In LRA Tables 3.5.2.1 through 3.5.2.26, the staff reviewed additional details of the results of the AMRs for MEAP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Tables 3.5.2.1 through 3.5.2.26, the applicant indicated, via Notes F through J, that the combination of component type, material, environment, and AERM does not correspond to a line item in the GALL Report, and provided information concerning how the aging effect will be managed. Specifically, Note F indicated that the material for the AMR line item component is not evaluated in the GALL Report. Note G indicated that the environment for the AMR line item component and material is not evaluated in the GALL Report. Note H indicated that the aging effect for the AMR line item component, material, and environment combination is not evaluated in the GALL Report. Note I indicated that the aging effect identified in the GALL Report for the line item component, material, and environment combination is not applicable. Note J indicated that neither the component nor the material and environment combination for the line item is evaluated in the GALL Report.

Staff Evaluation. During the onsite audit, the staff reviewed selected items in all applicable LRA Table 3.5 items for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

Carbon Steel in an Embedded/Encased Environment - It is recognized that all metals embedded/encased in concrete are inaccessible; however, they could be susceptible to aging degradation. The staff requested that the applicant provide an AMR for further evaluation of embedded/encased components if aging of components in accessible areas is identified that may indicate aging of the inaccessible components.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the BFN concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using ingredients conforming to ACI and ASTM Code standards, which provide for a good quality, dense, well cured, and low permeability concrete. Cracking is controlled through proper arrangement and distribution of reinforcing bars.

The applicant further stated that concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77.

The applicant also stated that, as a minimum, all exposed portions of embedded/encased carbon steel structural components are inspected by the Structures Monitoring Program for the following aging effects:

- outside air environments: loss of material due to general and pitting corrosion
- inside air environments: loss of material due to general corrosion
- containment air environments: loss of material due to general corrosion

The applicant concluded that the condition of the exposed portion of the embedded/encased carbon steel will provide an indication of the condition of the embedded/encased portion of the carbon steel. If a deficient condition were identified for the exposed portion of the embedded/encased carbon steel material, the Corrective Action Program (SPP-3.1) would document the deficient condition. Resolution of the deficient condition would require the development of a corrective action plan and consideration would be given to the extent of the deficient condition in the development of the corrective actions, which would include the embedded/encased portion of the material as warranted by the deficient condition.

The applicant also stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for carbon steel components embedded/encased in concrete.

The staff found that the applicant had identified an appropriate course of action, through its Corrective Action Program, to manage aging of carbon steel components embedded/encased in concrete, if a deficient condition is identified for the exposed portion of the embedded/encased carbon steel material. On this basis, the staff accepts the applicant's AMR results for carbon steel in an embedded/encased environment.

Stainless Steel in Containment Air, Inside Air and Outside Air Environments - The staff requested that the applicant provide the technical basis for concluding that the BFN stainless steel components do not require aging management for any aging effects/mechanisms in containment atmosphere, inside air, and outside air environments.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the AMR evaluation for stainless steel in a containment atmosphere, inside air, and outside air is not susceptible to loss of material in for these environments. Stainless steels form a passive film that prevents corrosion. Only a corrosive wetted environment is conducive to promoting aging degradation of stainless steel. Alternate wetting and drying in an outside air environment has shown a tendency to 'wash' the exterior surfaces, cleaning the surface rather than concentrating any corrosive contaminants (ref EPRI 1003056 Mechanical Tools). SCC of stainless steel, which is only considered plausible in wetted corrosive environments greater than 140 °F, will not occur in the containment atmosphere environment, inside air environment, or outside air environment.

The staff found the applicant's AMR results to be acceptable for stainless steel structural components and stainless steel non-ASME supports. In the absence of corrosive contaminants and temperatures greater than 140 °F, stainless steel material is not susceptible to loss of material due to corrosion and cracking due to SCC. Therefore, aging management for loss of material and cracking in the containment atmosphere environment, an inside air environment, or an outside air environment is not required.

In its response, the applicant also stated that ASME stainless steel equivalent supports are subject to the requirements of ASME Code Section XI, Subsection IWF during the period of extended operation. However, the staff determined that the applicant had not credited IWF for aging management of ASME stainless steel equivalent supports during the extended period of operation, because the applicant's AMR had not identified any applicable aging effects. The staff requested additional information to resolve this issue and related issues. The disposition is discussed in SER 3.5.2.3.26, as part of the review of LRA Table 3.5.2.26 AMRs.

For component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation. The staff's evaluation is discussed in the following sections.

3.5.2.3.1 Primary Containment Structures – Summary of Aging Management Evaluation – Table 3.5.2.1

The staff reviewed LRA Table 3.5.2.1, which summarizes the results of AMR evaluations for the primary containment structures component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.1, for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

Lubrite in a Containment Air Environment – The staff requested that the applicant describe where the referenced items are used and provide the technical basis for concluding that no aging management of the lubrite plates used in BFN is required in a containment atmosphere.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.1, row 37 applies to the lubrite plates used for the drywell floor beam seats. EPRI 1002950, "Aging Effects for Structures and Structural Components (Structural Tools), Revision 1," states that lubrite material 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. Lubrite products are solid, permanent, completely self lubricating, and require no maintenance. The containment atmosphere at the location of the drywell floor beam seats is not an aggressive or wetted environment.

The applicant also stated that a search of BFN and industry operating experience did not identify any instances of lubrite plate degradation or failure to perform its intended function due to aging effects. NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4" and NUREG-1769, "Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3," concur that there are no lubrite plate aging effects that require aging management.

Based on the additional information provided by the applicant, the staff finds the applicant's AMR results for lubrite plates to be acceptable. Prior staff evaluations of this issue have concluded that there are no aging effects requiring aging management.

The staff's review of LRA Table 3.5.2.1 identified areas in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's RAI as discussed below.

In RAI 3.5-1, dated December 10, 2004, the staff inquired about the leakage rate testing of containment penetration bellows by pointing out that LRA Table 3.5.1, Item Numbers 3.5.1.3 and 3.5.1.17, indicate that the AMR results are consistent with the GALL Report, with the exceptions described in ASME Code Section XI Subsection IWE Program. The GALL Report, Item B.1.1.1-d recommends further evaluation regarding the SCC of containment bellows. In the discussion of these items in LRA Section 3.5.2.2.1.7, the applicant asserted that Appendix J, Type B testing was effective in detecting leakages through the vent line bellows, as well as through other pressure boundary bellows. The staff requested the applicant to provide additional information regarding the frequency of Type B testing (performance-based intervals, in accordance with Option B, Appendix J) of containment pressure boundary bellows at Units 2 and 3, and the status of these bellows for Unit 1.

In its response, by letter dated January 31, 2005, the applicant quoted the content of LRA Section 3.5.2.2.1.7 and then stated:

> BFN pipe penetration bellows are 10 CFR 50, Appendix J, Type B tested. BFN vent line bellows are 10 CFR 50, Appendix J, Type A tested.
>
> Type B and C tests are performed prior to initial reactor operation. Subsequent Type B and C tests are performed at a frequency of at least once per 30 months until performance data are collected for evaluation for extended test interval in accordance with RG 1.163. Type B tests may use an extended interval of up to 120 months (excluding airlocks). Unit 2 and 3 bellows are tested at a 60-month test interval. There have been no bellows failures on either Unit 2 or 3 bellows. Prior to the restart of Unit 1, Appendix J, Type B testing of containment pipe penetration bellows will be performed. Unit 1 bellows will be tested at least once per 30 months until test performance data is available to justify an extended test interval under Option B.

The staff noted that the vent line bellows are single-ply, and their leakage rates and aging degradation are managed by Appendix J, Type A testing. As Appendix J, Type A testing is generally performed at 10-year intervals or greater, it was not clear to the staff how the leaktightness and structural integrity of the vent line bellows were maintained. The applicant was requested to provide the frequency at which the Type A testing is performed in each unit, and the process by which the integrity of the vent line bellows is maintained, including corresponding operating experience.

In its letter dated May 31, 2005, the applicant stated that it has been granted a one-time 5-year extension by the staff for performing the Type A test, and emphasized that there had been no performance-based Type A test failure on Units 2 or 3. The applicant plans to perform an Appendix J, Type A integrated leak rate test (ILRT) on Unit 1 prior to restart. The Unit 1 Appendix J, Type A test will be performed at least once every 48 months until test performance data are available to justify an extended test interval under Option B. Moreover, the applicant provided a detailed description of the history of the visual examinations performed under its plant procedures 2-TI-173 and 3-TI-173 which performs a general visual examination each inspection period (three periods per 10 year interval). Different from other BWR Mark I containments, the single-ply vent line bellows at the three BFN units are accessible for examination from the torus interior. A VT-3, visual examination is performed each inspection interval in accordance with plant procedure 0-TI-376. The applicant emphasized that these examinations are thorough as they are performed by NDE-certified personnel with specific lighting and visual acuity requirements. Additionally, plant procedure 0-SI-4.7.A.2.K, "Primary Containment Drywell Surface Visual Examination," is performed each operating cycle.

Based on the detailed response regarding the detection of flaws in vent line bellows provided by the applicant, the staff found the applicant's process for ensuring the integrity of the vent line bellows acceptable. Therefore, the staff's concern described in RAI 3.5-1 is resolved.

In RAI 3.5-2, dated December 10, 2004, the staff stated that, for seals and gaskets related to containment penetration, LRA Table 3.5.1, Item Number 3.5.1.6 and component type, "Compressible Joints and Seals," in LRA Table 3.5.2.1, the ASME Code Section XI Subsection IWE Program and the 10 CFR 50 Appendix J Program have been identified as AMPs. Based on Exception 1 in the ASME Code Section XI Subsection IWE Program, the AMP will not be applicable for aging management of containment seals and gaskets. For equipment hatches and air-locks, the assumption is that the leak rate testing program will monitor aging degradation of seals and gaskets, as they are leak rate tested after each opening. Therefore, the staff requested that the applicant clarify whether these assumptions are correct. For other penetrations (mechanical and electrical) with seals and gaskets, the applicant was requested to provide information regarding the adequacy of Type B leak rate testing frequency to monitor aging degradation of seals and gaskets of containment drywells. The applicant was also requested to provide the status of seals and gaskets of these penetrations at Unit 1.

In its response, by letter dated January 31, 2005, the applicant stated:

> ASME Section XI, 1992 Edition, 1992 Addenda, Category E-D, Item Numbers E5.10 (Seals), and E5.20 (Gaskets) requires a visual examination, VT-3, of containment seals and gaskets. Examination of most seals and gaskets requires the joints to be disassembled. When the airlocks, hatches, electrical penetrations, and flanged connections are tested in accordance with 10 CFR 50, Appendix J, degradation of the seal or gasket material would be revealed by an increase in the leakage rate. Corrective measures would be applied and the component retested.
>
> For Units 1, 2, and 3, Relief Request CISI-1 was granted to perform Appendix J test in lieu of the visual examination, VT-3, on the containment seals and gaskets. The moisture barriers continue to receive a visual VT-3 examination in accordance with Category E-D for Units 1, 2, and 3. The scope of the 10 CFR 50 Appendix J Program includes all pressure-retaining components, the containment shell (drywell and torus) and penetrations. The following components are included in the scope of the program:
>
> - containment penetration seals on airlocks, hatches, spare penetrations with flange connections, electrical penetrations and other devices required to assure containment leak-tight integrity;
> - containment penetration gaskets on airlocks, spare penetrations with flange connections, and other devices required to assure containment leak-tight integrity;
> - pressure retaining bolted connections;
> - containment penetration bellows; and
> - airlocks.
>
> Units 2 and 3 O-ring seals (flanges, hatches, etc.) are tested on either a 30 or 60-month interval. Seal failures have occurred sporadically since restart. The Unit 2 and Unit 3

drywell heads have experienced failures and are currently classified as Maintenance Rule (a)(1) for corrective actions. There are currently no electrical penetration performance problems on Unit 2. All electrical penetrations on Unit 2 are currently on a 120-month test interval. Testing has identified only minor problems such as gauge, tubing, and root valve leaks. Unit 3 electrical penetrations are on 30, 60, or 72-month test intervals. In general, testing has identified only minor problems such as gauge, tubing, and root valve leaks. However, one electrical penetration (3-EPEN-100-0101C) on Unit 3 experienced a failure, was repaired, and is being tested on a 30-month test interval. Other electrical penetrations are being tested at a 60-month interval. The remainder of the Unit 3 electrical penetrations are on a 72-month interval.

> Type B testing will be performed as part of the Unit 1 restart effort and will continue at least once per 30 months until test performance data is available to justify an extended test interval under Option B.

The applicant described the existing process used in identifying degradation of the primary containment penetration seals and gaskets and plans to continue with the testing and corrective action process during the period of extended operation. Therefore, the staff found the applicant's process for managing the aging of the pressure-retaining seals and gaskets of primary containments acceptable. The staff's concerns described in RAI 3.5-2 are resolved.

In RAI 3.5-3, dated December 10, 2004, the staff stated that the containment drywell-head to drywell joint consists of a pressure unseating containment boundary with pre-loaded bolts. Loosened bolts and deteriorated gasket and/or seals can breach containment pressure boundary. Exceptions 1 and 2 taken in the ASME Section XI Subsection IWE Program will preclude examinations of seals and bolts of this joint. Only Type A leak rate testing and associated visual examination requirements of the 10 CFR 50 Appendix J Program can be relied upon to detect defects and degradation of this joint. The test interval for Type A leak rate testing can be 10 to 15 years. Therefore, the staff requested the applicant to provide (1) information regarding the plans and programs that are used to ensure the integrity of this joint for each containment and (2) the status of the components (O-rings and bolts) at this joint for Unit 1.

In its response, by letter dated January 31, 2005, the applicant stated:

> These containment pressure boundary components will continue to be inspected consistent with the Browns Ferry CLB for 10 CFR Part 50, Appendix J requirements. On Units 2 and Unit 3 the Type A test frequency is currently on a 10-year interval. There have been no performance based Type A test failures on Unit 2 or Unit 3. A Type A Integrated Leak Rate Test will be performed as part of the Unit 1 restart effort. Type B testing is also performed on the drywell-head seal every refueling outage for all three units. Therefore, in combination of the Type A tests and Type B tests, integrity for this joint for each containment is assured. Exception 2 pertains to bolt torque or tension testing. Pressure retaining bolting associated with the Containment drywell-head to drywell joint is examined in accordance with ASME Section XI Subsection IWE.

The applicant performs Type B testing of the drywell-head seal every outage, and examines the pressure retaining bolts of the drywell head in accordance with Subsection IWE of the ASME Section XI Code. The staff accepts that these two activities together with periodic Type A testing will ensure the integrity of this joint. Therefore, the staff found the applicant's practice of ensuring the integrity of this joint acceptable. The staff's concern described in RAI 3.5-3 is resolved.

In RAI 3.5-4, dated December 10, 2004, the staff stated that the water leakages from the sand drains have been found in Units 2 and 3, and the results of the UT examinations performed from the accessible areas of the drywells have indicated that the condition of the drywell shells was good, and these areas did not require augmented examination. Therefore, the staff requested that the applicant provide the following additional information related to the drywell shell corrosion in this area for each containment drywell:

a. In other Mark I containments, the cause of water leakage from the sand-bed drains has been found to be water leaking from the refueling cavity (see IN 86-99, "Degradation of Steel Containments)." As no water leakage has been indicated from Unit 1 (having no refueling activities during its long layup), it would appear that the cause of the water leakage in Units 2 and 3 could be the same as that described in the information notice. Provide a discussion of the root cause in this context.

b. If the water leakage is related to refueling operation, provide information regarding the corrosion susceptibility of the cylindrical part of the drywell shell on the insulation (inaccessible) side.

c. Item No. E4.12 of Examination Category E-C of Subsection IWE requires the owner to establish grid and measurement locations in the suspect areas identified for augmented examinations. Provide information regarding the methods used to establish a confidence level that no drywell shell corrosion exists in the sand-pocket areas.

d. Unless preventive actions are taken and conditions verified that no leakage and shell corrosion exists in the suspect areas, IWE will require continuation of UT measurements in the augmented examination areas. Provide justification for excluding the suspect areas from augmented examinations.

e. Based on the results of the UT examinations performed from the accessible areas of the drywells, BFN asserted that the condition of the drywell shells is good. Provide a discussion of BFN's criteria for judging that the condition of the drywell steel liner plate is good and the rationale for the criteria.

f. Provide a discussion of any degradation observed and/or repair work implemented as a result of past general visual inspection of the moisture barrier located at the junction of the steel drywell and the concrete floor.

In its response, by letter dated January, 31, 2005, the applicant stated:

a. See response to item "b."

b. A postulated failure of the drywell-to-reactor building refueling seal can result in water intrusion into the annulus space around the drywell. This leakage can occur only during refueling outages when the reactor cavity is flooded to allow movement of fuel between the reactor and the fuel pool. However, water intrusion does not cause failure of the drywell's intended function. Any water leakage resulting from a postulated failure of the drywell-to-reactor building refueling seal could not remain suspended in the annulus region for an indefinite period of time and would eventually be routed to the sandpocket area drains or would evaporate due to the heat generated in the drywell during operation. In TVA's response to NRC Generic Letter 87-05 dated August 30, 1988, which addressed the potential for corrosion of boiling water reactor (BWR) Mark I steel drywells in the "sand pocket region," TVA provided the NRC with the results of the ultrasonic testing for corrosion degradation of drywell liner plate. The results of the ultrasonic testing states: Each unit's drywell was ultrasonically tested near the sand cushion area during 1987. The results from these tests showed that the nominal thickness was maintained on each drywell. Below are the results of each unit's drywell ultrasonic testing:

- Unit 1 - No reading below the nominal thickness of one inch was measured indicating that the integrity of the drywell liner plate is maintained. Periodic leakage from the sand cushion area has been observed. Corrosive species in the drainage are bases to suspect a higher rate of corrosion on Unit 1 drywell liner plate than on Unit 2 and 3. However, objective evidence of serious corrosion damage was not noted.
- Unit 2 - No reading below the nominal thickness of one inch was measured indicating that no damage to the integrity of the drywell liner plate has occurred.
- Unit 3 - No reading below the nominal thickness of one inch was measured indicating that no damage to the integrity of the drywell liner plate has occurred.

c. In response to NRC Generic Letter 87-05, TVA provided the NRC with the results of the ultrasonic testing for corrosion degradation of BFN Units 1, 2, and 3 drywell liner plates near the sand cushion area during 1987. The results from these tests showed that the nominal thickness was maintained on each drywell. Paragraph IWE-1242 of ASME Section XI requires the Owner to determine containment surface areas requiring augmented examination, in accordance with Paragraph IWE-1241. UT thickness measurements of this area were obtained during the U2C10 and U3C8 refueling outages for Units 2 and 3 respectively and in 1999 and 2002 for Unit 1 (0-TI-376 Appendix 9.7 page 4). The data indicate that the condition of the drywell steel liner plate in this area meets code requirements, and that this area should not be categorized for augmented examination.

d. See response to Item c.

e. See response to Item c.

f. The internal drywell steel containment vessel (SCV) embedment zone is subject to corrosion if the drywell floor-to containment vessel moisture barrier fails, allowing moisture intrusion, or if the concrete floor of the drywell cracks, allowing moisture seepage through to the steel liner. During the Unit 2 Cycle 9 outage, a portion of the moisture barrier was replaced (Problem Evaluation Report (PER) BFPER971516). Engineering personnel performed an examination of the exposed drywell SCV area below the moisture seal. This inspection indicated some minor pitting and localized rust, but nothing approximating a challenge to nominal wall thickness. No propagation of iron oxide to the concrete surface was noted, which would be indicative of steel containment vessel corrosion below the concrete. Inspections conducted by the Containment ISI Program during Unit 2 Cycle 10 refueling outage and Unit 3 Cycle 9 refueling outage also identified some damaged areas of the moisture barrier (gaps, cracks, low areas/spots, or other surface irregularities) that were evaluated by engineering and replaced or repaired. (PER 99-005254-000 for Unit 2 Drywell moisture seal barrier and PER 00-004163-000 for Unit 3 Drywell moisture seal barrier).

In Unit 1, the moisture barrier in areas that would be made inaccessible due to ductwork installation have been replaced. Visual examination of exposed drywell SCV area below the moisture barrier identified some minor pitting. Ultrasonic thickness and pit depth measurements were taken and evaluated by engineering which confirmed nominal wall thickness was not encroached. The entire Unit 1 moisture barrier will be replaced before restart.

The Structures Monitoring Program also monitors the concrete to ensure that it is free of penetrating cracks that provide a path for water seepage to the surface of the containment shell. Research of plant history did not reveal any instances of water spills and water ponding on the containment concrete floor. A general visual inspection of the moisture barrier at the junction of the steel drywell shell and the concrete floor is performed once each inspection interval in accordance with the ASME Section XI, Subsection IWE aging management program.

Based on the responses, the staff understood that for each unit the applicant has taken actions to monitor corrosion of the outside surface of the drywell shell and the inside surface at the junction of the concrete floor and the drywell shell. However, the extent of monitoring the parameters associated with the degradation and the root cause(s) of the corrosion problems are not clear.

The response to RAI 3.5-4 emphasizes that the existing degradation of the drywell shells (inside and outside) has not reached the minimum required thickness of one inch. However, the response does not address a number of parameters that are pertinent to the period of extended operation. In a follow-up to RAI 3.5-4, dated April 5, 2005, the applicant was requested to provide (1) a description of the type of degradation (e.g, a cluster of pits or general corrosion), (2) a description of preventive actions (e.g. stopping the leaks from the refueling cavity seals or monitoring of sand drains), (3) a description of corrective actions (repairing/cleaning and recoating degraded areas), (4) a description of the extent of degradation, and (5) when IWE-1240 requirement for augmented inspection will be implemented.

In its letter dated May 31, 2005, the applicant stated that during each refueling outage since the mid-1980s, a visual inspection of the interior surface of the drywell, and the interior and exterior surface of the drywell head and torus (suppression chamber) was performed to verify structural integrity. These inspections are performed per SI 0-SI-4.7.A.2.K, "Primary Containment Drywell Surface Visual Inspection," and BFN Technical Instruction 0-TI-417, "Inspection of Service Level I, II, III Protective Coatings." SI 0-SI-4.7.A.2.K originally included the exam requirements for the visual inspections of the protective coatings but was revised in March 2001 to remove those requirements and add the reference to BFN Technical Instruction 0-TI-417 for coating inspections. BFN Technical Instruction 0-TI-417 was written to incorporate the information for performing visual inspections of Service Level I protective coatings (design-basis accident (DBA) and non-DBA qualified). This procedure was implemented in March 2001. The scope of SI 0-SI-4.7.A.2.K, as defined in the procedure, is as follows:

(1) Includes provisions for the visual verification of the structural components of the drywell, drywell head, torus (suppression chamber), and the exterior surfaces of the drywell head

and torus (suppression chamber) (i.e., piping, connections, structural supports, penetrations, platform steel, duct supports, concrete walls, and steel shell) by visually inspecting for deterioration and/or structural damage.

(2) Provides visual inspection of the moisture seal barrier located on drywell elevation 550 feet.

(3) Provides for visual inspection of the interior surfaces of the drywell and torus (suppression chamber) above the level one foot below the normal water line and exterior surface of the torus (suppression chamber) below the water line each operating cycle for deterioration and any signs of structural damage with particular attention to piping connections and supports and for signs of distress or displacement. In its response, the applicant provided the results of the earlier inspections of the drywell internal components for each unit.

Based on the detailed response, the staff found that the applicant has in place detailed procedures for examining the concrete and steel components inside the drywell, and systematic acceptance criteria. The applicant plans to continue this process during the extended period of operation. Therefore, the staff found the applicant's process of detecting degradation of these components adequate and acceptable, and the staff's concern described in RAI 3.5-4 is resolved.

In RAI 3.5-5, dated December 10, 2004, the staff stated that a number of load-bearing reinforced concrete structures within the drywell shell were subjected to temperatures higher than the established threshold of 150°F, as discussed in LRA Section 3.5.2.2.2.1. The effectiveness of the closed cooling ventilation system is paramount in preventing large temperature excursions in the drywells. Therefore, the staff requested that the applicant provide the following information related to the concrete structures within the drywells of each unit.

a. Provide a summary of the operating experience related to the reliability of the closed cooling ventilation system.

b. Provide a summary of the results of the last inspections performed on (1) reactor pressure vessel (RPV) pedestal supports, (2) the foundation and floor slab, and (3) the sacrificial shield wall under the existing Structural Monitoring Program.

c. LRA Section 3.5.2.2.2.1, Item 8, states that the main steam tunnels in the reactor building at Units 1, 2, and 3 have a maximum normal space ambient temperature of 160°F. Provide a discussion, including a summary of the results of the engineering analysis performed, to support the conclusion that the conditions identified in the GALL Report are satisfied and that aging management of reduction of strength and modulus due to elevated temperature for the affected concrete components is not required.

In its response, by letter dated January 31, 2005, the applicant stated:

> Note that LRA Section 3.5.2.2.2.1, Item 8 states in part: "The upper elevations of the sacrificial shield wall may exceed 150°F briefly and infrequently, during abnormal operations and is not considered to affect its function." The upper elevation of the sacrificial shield wall inside the drywell shell is not a load bearing reinforced concrete structure.

a. The drywell closed cooling ventilation system is a non-safety related system and not in scope for License Renewal. This function is not required for Safe Shutdown of the plant. If this cooling system function is lost, operator action will be required when the Technical Specifications for drywell temperature limits exceeds 150 °F.

b. A review of Browns Ferry Structures Monitoring Baseline inspection and the results for the first Structures Monitoring inspection period did not reveal any loss of intended function due to aging effects of the RPV pedestal supports, the foundation and floor slab, and the sacrificial shield wall.

c. Appendix A of ACI 349-85 specifies that the concrete temperature limits for normal operation or any other long term period shall not exceed 150 °F except for local areas, which are allowed to have increased temperatures not to exceed 200 °F. With the exception of the main steam tunnels in the Reactor Building, BFN reinforced concrete structures have general area temperatures less than 150 °F during normal operation. The general area temperatures have been conservatively evaluated using maximum normal space ambient temperatures noted on the Harsh Environmental drawing series and associated calculations. The Unit 1, 2, and 3 main steam tunnels at BFN have a maximum normal space ambient temperature of 160 °F as noted in the Harsh Environmental drawing series and associated calculations. Note however, that this is a maximum normal space ambient temperature. The TVA Harsh Environmental drawing series and associated calculations identify the average normal space ambient temperature as 135 °F. This is judged to be acceptable because when concrete is subjected to prolonged exposure to elevated temperatures, reductions in excess of 10 percent of the compressive strength, tensile strength, and the modulus of elasticity only begin to occur in the range of 180 °F to 200 °F. (Reference EPRI TR-103842, July 1994).

Therefore, the conditions identified in NUREG-1801 are satisfied and aging management of reduction of strength and modulus due to elevated temperature for concrete components at BFN is not required.

The staff recognizes the temperature thresholds, and accepts the EPRI TR position. However, at these temperatures, the concrete structures go through additional shrinkage cracking, and spalling. The staff's basic concern was related to the degradation of pedestals supporting the reactor vessels and that of the seismic restraints anchored to the sacrificial shields and the drywell. The staff expected more description regarding the concerns in response to item "b." In this context, in a follow up letter, April 5, 2005, the applicant was requested to provide (1) the type and extent of degradation observed in the reactor pedestals and at the seismic restraint anchorage areas, and (2) the acceptance standards established (e.g., ACI 349-3R, ASME Code Subsection IWE) for corrective actions.

In its response, by letter May 24, 2005, the applicant stated that the inspection of concrete within the drywell is conducted per BFN "Procedure Walkdown of Structures for Maintenance Rule" (LCEI-CI-C9). This LCEI provides the basis for monitoring/inspection tasks, examination criteria, evaluation requirements, and acceptance criteria in compliance with the Maintenance Rule. A baseline inspection was established in 1997 and subsequent inspections are performed on a five-year frequency. LCEI-CI-C9 Section 7.2 provides inspection guidelines, and visual inspections of structural conditions are used to detect degradation. Visual inspection is an acceptable technique and is consistent with techniques identified in industry codes and standards such as ACI 349.3R-96. Inspection checklists (LCEI-CI-C9 Attachment 1) are used to document inspection results/defects.

LCEI-CI-C9 Section 7.3 provides guidance for evaluation of the results documented on the inspection checklists. The acceptance criteria are defined in LCEI-CI-C9 Section 7.3 as: (1) acceptable, (2) acceptable with deficiencies, and (3) unacceptable. The latest inspection of the concrete of the reactor vessel support pedestal, biological or sacrificial shield wall, and other structural concrete within the primary containment structure had been completed by 2002 for Units 2 and 3. All concrete elements within the primary containment structure for Units 2 and 3 were found to be acceptable.

The staff found the inspection procedure used to detect deterioration of the concrete structures inside drywell adequate and acceptable, as its continued use during the period of extended operation will ensure the intended functions of these components. Therefore, the staff's concern described in RAI 3.5-5 is resolved.

In RAI 3.5-6, dated December 10, 2004, the staff stated that LRA Table 3.5.2.26 is silent on the AMR related to Class MC supports. ASME Section XI Subsection IWE Program takes exception to NUREG-1801 Section XI.S3, and states that the aging effects for supports of MC components will be managed by the Structures Monitoring Program or Chemistry Control Program with associated One-Time Inspection Program for submerged supports during the extended period of operation. Therefore, the staff requested that the applicant provide the following information related to the aging management of Class MC supports:

- Provide the results of the AMR for (1) MC component supports within the BFN containments, (2) MC component supports outside the containments, and (3) supports for piping penetrating through the containments and designated as MC piping (if any). Also, summarize the program (sample size, inspection frequency, personnel qualification, etc.) used to arrive at the AMR results.
- Section 50.55a(g)(4) of 10 CFR requires the inservice inspections of Class MC pressure retaining components and their integral attachments, in accordance with the requirements of ASME Code Section XI. ASME Code Section XI Subsection IWF sets the examination requirements for Class MC supports, other than those for the MC piping supports. Therefore, provide justification for the exception taken in ASME Code Section XI Subsection IWF Program regarding the aging management of Class MC component supports.
- Subsections IWE and IWF do not incorporate explicit requirements for inservice inspection of supports of pipes designated as Class MC; therefore, the applicant was requested to provide a description of a proposed AMP (could be part of the Structural Monitoring Program), including sample size, the extent of examination, frequency of examination, and qualification of personnel who perform and evaluate the inspection results.

In its response, by letter dated January 31, 2005, the applicant noted that the information requests made in RAI 3.5-6 are addressed in the responses to RAIs 2.4-2, 2.4-13(a) & (b) and B.2.1.33, dated January 24, 2005. Finally, by letter dated May 31, 2005, the applicant agreed to bring the inspection and inspector qualification with regards to Class MC supports into the scope of ASME Section XI Subsection IWF Program (see SER Section 3.0.3.2.21 for staff evaluation of the ASME Section XI Subsection IWF Program). After comprehensively reviewing all responses to the indicated RAIs, above, the staff concluded that the applicant had successfully resolved all of the staff issues with regard to this and the other RAIs indicated.

The staff also reviewed the information provided in LRA Section 3.5.2.1.1 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the primary containment structures components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the primary containment structures components acceptable.

3.5.2.3.2 Reactor Buildings – Summary of Aging Management Evaluation – Table 3.5.2.2

The staff reviewed LRA Table 3.5.2.2, which summarizes the results of AMR evaluations for the reactor buildings component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.2, for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

Ceramic Fiber in an Inside Air Environment - The staff requested that the applicant provide the BFN technical basis for concluding that no aging management is required for ceramic fiber fire barriers in an inside air environment.

The following list identifies the ceramic fiber components in an inside air environment:

- reactor building fire barriers
- diesel generator building fire barriers

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that ceramic and glass fiber used to seal fire barrier penetrations do not have any applicable aging effects requiring aging management. This is consistent with previous staff positions in that there are no applicable aging effects for glass used in a metal fire barrier penetration. This is also consistent with the NUREG-1769 "Safety Evaluation Report Related to License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3," dated January 31, 2003,which concurred that insulation made of aluminum, stainless steel (mirror), calcium silicate, ceramic fiber, or fiberglass in a sheltered environment does not have any aging effects requiring aging management.

The applicant further stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for the following ceramic fiber components.

- reactor building fire barriers
- diesel generator building fire barriers

The staff concluded that the applicant had not credited an existing AMP (structures monitoring and/or fire protection) that already includes fire barriers in its scope, on the basis that its AMR did not identify any applicable aging effects.

Earthfill & Rock in a Buried Environment - This item indicates that the equipment supports and foundations are earth fill (rock and sand). The staff requested that the applicant explain the technical bases for concluding that there are no aging effects requiring management.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the foundation for the condensate water storage tank (CWST) is comprised of a concrete ring foundation with the interior portion of the ring foundation filled with crushed rock and sand. The earthen materials (rock and sand) of the CWST foundation interior base are protected from environmental weathering conditions by the concrete perimeter ring and CWST tank bottom. There are no aging effects for the earthen materials of the CWST foundation interior base that require aging management. Aging management of the CWST concrete foundation ring is managed by the Structures Monitoring Program. Aging management of the CWST bottom will be performed by the One-Time Inspection Program.

The applicant also stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for earthen materials of the CWST foundation interior base.

Based on the additional information provided by the applicant, the staff concurred with the applicant's AMR results for the crushed rock and sand base of the CWST. The staff concluded that aging management is not required because these materials are adequately protected by the concrete perimeter ring and the CWST tank bottom.

Elastomers in an Embedded/Encased Environment - The staff requested the applicant to clarify whether the compressible joints and seals that are embedded/encased in concrete are accessible for monitoring. If not, the staff requested the applicant to explain how the Structures Monitoring Program is utilized to manage aging effects in inaccessible areas.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Table 3.5.2.2, rows 4 and 5, apply to the seal around the reactor building access doors. Row 4 applies to the portion of the seal that is embedded/encased, and row 5 applies to the portion of the seal that is exposed to the inside air environment of the reactor building. An embedded/encased environment will minimize aging effects due to elastomer degradation caused by inside air environment (ambient conditions of ultraviolet radiation, ozone, temperature, etc.). The Structures Monitoring Program will periodically inspect the portion of the seal that is exposed to the inside air environment of the reactor building for aging effects due to elastomer degradation. The condition of the exposed portion of the seal will provide an indication of the condition of the embedded/encased portion of the seal. The inaccessible portions of the embedded/encased seal for the reactor building access door will be monitored with the periodic inspections of the seal that are exposed to the air environment of the reactor building.

Based on the additional information provided by the applicant, the staff finds the applicant's AMR results for the embedded/encased portion of the seal around the reactor building access doors to be acceptable. The condition of the exposed portion of the seal will be periodically inspected by the Structures Monitoring Program, which will provide an indication of the condition of the embedded/encased portion of the seal.

Stainless Steel in an Embedded/Encased Environment – All metals embedded/encased in concrete are inaccessible; however, they could be susceptible to aging degradation. The staff requested that the applicant provide an AMR to further evaluate embedded/encased components if aging of components in accessible areas is identified that may indicate aging of the inaccessible components.

The following list identifies stainless steel components that are embedded/encased:

- mechanical penetrations
- spent fuel pool liners

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the BFN concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using ingredients conforming to ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete. Cracking is controlled through proper arrangement and distribution of reinforcing bars. Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77.

The applicant also stated that the AMR for the material and environment combination of stainless steel in an embedded/encased environment was performed and concluded that no aging mechanism was identified that requires management. The applicant noted that the submerged surfaces of spent fuel pool liners are managed by the Chemistry Control Program and monitoring of the spent fuel pool level is managed by plant operations.

The applicant further stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for stainless steel mechanical penetrations or spent fuel pool liners that are embedded/encased in concrete.

The staff found that the applicant had identified an appropriate course of action to manage aging of stainless steel submerged surfaces of spent fuel pool liners because it is consistent with the guidance in the GALL Report. For other stainless steel structural components embedded/encased in concrete, the staff accepted the applicant's AMR results that aging management is not required, because stainless steel structural components in general are not susceptible to degradation, and concrete provides protection for embedded/encased steel.

The staff's review of LRA Table 3.5.2.2 identified areas in which additional information was necessary to complete the review of the applicant's results. The applicant responded to the staff's RAIs as discussed below.

In RAI 3.5-7, dated December 10, 2004, the staff stated that the buried environment item in LRA Table 3.0.2 states that ground water is non-aggressive. Therefore, the staff requested that the applicant provide historical site ground water chemistry test results together with a discussion of the extent of past ground water sampling and testing frequency, as well as the extent of fluctuation of the test results to support the above assertion.

In its response, by letter dated January 31, 2005, the applicant stated:

> Since BFN did not have data available from the construction period or since plant start-up, baseline sampling was performed over the past year of groundwater and the Wheeler Reservoir. The baseline sampling was to establish if BFN had aggressive or non-aggressive water as defined by the following criteria: pH <5.5, Chlorides > 500 ppm and Sulfates > 1500 ppm. The samples were taken at intervals to take into consideration seasonal variations. The samples were taken from the existing site radiological monitoring wells and from the Wheeler Reservoir in close proximity to the Intake Pumping Station structure. Samples were taken at various depths in the monitoring well and the Reservoir by the site environment staff and analyzed by an off-site laboratory for the site environment group. Results of Browns Ferry groundwater and Wheeler Reservoir water sampling are as follows:
>
> a. Groundwater:
>
> - pH ranges from 6.33 to 8.77 which are well above <5.5 (Note in the well that the value 6.33 was obtained, the remaining pH readings ranged from 7.16 to 7.60 during the time period of sampling. Only one other well had a pH value below 7 and its pH was 6.92 with the remaining readings ranging between 7.12 and 7.6)
> - Chlorides – maximum reading of 18.3 ppm which is well below the threshold of 500 ppm
> - Sulfates–maximum reading of 30.3 ppm which is well below the threshold of 1500 ppm
>
> b. Wheeler Reservoir:
>
> - pH ranges from 7.28 to 8.64 which are well above < 5.5
> - Chlorides – maximum reading of 13.9 ppm which is well below the threshold of 500 ppm
> - Sulfates – maximum reading of 15.5 ppm which is well below the threshold of 1500 ppm
>
> Browns Ferry groundwater and Wheeler Reservoir sample measurements have confirmed that parameters are well below threshold limits that could cause concrete degradation (i.e., an aggressive environment does not exist).

Based on the above test data, the staff found that both the Browns Ferry groundwater and the Wheeler Reservoir water are non-aggressive. Therefore, the staff's concern described in RAI 3.5-7 is resolved.

In RAI 3.5-8, dated December 10, 2004, the staff stated that the AMR discussion provided in LRA Section 3.5.2.2.2.2 is rather general and brief, and requires more detailed elaboration to support BFN's conclusion that the conditions identified in the GALL Report, as revised by ISG-03, are satisfied and no aging management for below-grade inaccessible concrete is needed. Therefore, the staff requested that the applicant provide additional specific information, including: (1) concrete quality and test data for inaccessible concrete, (2) past operating experience regarding exposure of inaccessible concrete to aggressive chemical/fluid environment, and (3) past inaccessible concrete inspection findings and data related to concrete degradation and repairs.

In its response, by letter dated January 31, 2005, the applicant stated:

(1) The BFN concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using ingredients conforming to ACI and ASTM standards, which provide for a good quality, dense, well cured, and low permeability concrete. Cracking is controlled through proper arrangement and distribution of reinforcing bars. Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77.

(2) As noted in the response to RAI 3.5-7, Browns Ferry groundwater water and Wheeler Reservoir sample measurements have confirmed that parameters are well below threshold limits that could cause concrete degradation (an aggressive environment does not exist).

(3) A review of Browns Ferry operating history, the Browns Ferry Structures Monitoring Baseline inspection, and the results for the first Structures Monitoring inspection period did not reveal any loss of intended function due to aging effects when below-grade inaccessible concrete was excavated for other reasons.

Based on the plant-specific operating experience reported in item 3 and the fact that the applicant complied with applicable provisions of the GALL Report, the staff found the applicant's response acceptable, and the staff's concern described in RAI 3.5-8 is resolved.

In RAI 3.5-9, dated December 10, 2004, the staff stated that in LRA Table 3.5.2.2, no AERM and AMPs are identified for hatches/plugs, and electrical and instrumentation and control (I&C) penetrations made of carbon and low-alloy steel that are embedded or encased in concrete; whereas, GALL Report Item III.A2.2-a calls for a Structures Monitoring Program to manage the loss of material and corrosion aging effects for steel components exposed to various environments. Additionally, the mechanical penetrations listed in Table 3.5.2.2 and the structural steel beams, columns, plates, and trusses that are embedded or encased in concrete are also identified as having no applicable aging effect that requires aging management; therefore, no AMP is designated for the components. This same BFN position is shown throughout the remainder of LRA Table 3.5.2.2. Therefore, the staff requested the applicant to discuss past operating experience and inspection results related to aging degradation of embedded or encased hatches, plugs, duct banks, manholes, mechanical penetrations, and electrical and I&C penetrations in order to provide an operating experience-based rationale to justify its assertion that these components require no AMP to manage their aging.

In its response, by letter dated January 31, 2005, the applicant stated:

> The BFN concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using materials conforming to ACI and ASTM standards, which provide for a good quality, dense, well cured, and low permeability

concrete. Cracking is controlled through proper arrangement and distribution of reinforcing bars.

Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77. As a minimum, all exposed portions of embedded carbon steel structural components are inspected for the following aging effects:

- Outside Air Environments: Loss of material due to general and pitting corrosion
- Inside Air Environments: Loss of material due to general corrosion
- Containment Air Environments: Loss of material due to general corrosion

A review of Browns Ferry operating history, the Browns Ferry Structures Monitoring Baseline inspection, and the results for the first Structures Monitoring inspection period did not reveal any loss of intended function due to aging effects for carbon steel components embedded/encased in concrete.

Based on the above plant-specific operating experience and the fact that concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using materials conforming to ACI and ASTM standards, which provide for a good quality, dense, well-cured, and low permeability concrete, the staff found that the applicant had adequately justified its AMR results regarding the concrete elements listed in LRA Table 3.5.2.2. Therefore, the staff's concern described in RAI 3.5-9 is resolved.

In RAI 3.5-10, dated December 10, 2004, the staff noted that non-ferrous aluminum electrical and I&C penetrations embedded or encased in concrete are listed in the second item of LRA Table 3.5.2.2 as components requiring no AMP to manage any aging effect. Therefore, the staff requested the applicant to provide a discussion of past and applicable industry operating experience to justify this AMR finding. Additionally, referring to embedded or encased stainless steel spent fuel pool liners listed in LRA Table 3.5.2.2, the applicant was requested to discuss applicable operating experience of these liners to justify its AMR results that no AMP is needed to manage any aging effect.

In its response, by letter dated January 31, 2005, the applicant stated:

> The BFN concrete structures and concrete components are designed in accordance with ACI 318-63 and 71 and constructed using materials conforming to ACI and ASTM standards, which provide for a good quality, dense, well cured, and low permeability concrete. Cracking is controlled through proper arrangement and distribution of reinforcing bars.
>
> Concrete structures and concrete components are constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio that is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI 201.2R-77.
>
> Embedded or Encased Aluminum Response: Aluminum is a reactive metal, but it develops an aluminum oxide film that protects it from further corrosion in an indoor

environment. The specific aluminum alloy (6063-T42) used at BFN for conduit and raceways is resistant to general corrosion, pitting, and SCC during testing in outdoor, and saltwater environments. For the aluminum that is embedded/encased within the concrete, corrosion is not considered an applicable aging mechanism. The concrete must first be degraded by other aging mechanisms, which reduce the protective cover and potentially allow for the intrusion of aggressive ions causing a reduction in concrete pH. Aging management of concrete aging effects will manage the corrosion of the embedded/encased aluminum's concrete protective cover. A review of Browns Ferry operating history, the Browns Ferry Structures Monitoring Baseline inspection, and the results for the first Structures Monitoring inspection period did not reveal any loss of intended function due to aging effects for aluminum components embedded/encased in concrete.

Embedded or Encased Stainless Steel Response: For the stainless steel that is embedded/encased within the concrete, corrosion is similarly not considered an applicable aging mechanism. The concrete must first be degraded by other aging mechanisms, which reduce the protective cover and allow for the intrusion of aggressive ions causing a reduction in concrete pH. Adequate management of other concrete aging effects will in effect manage the aging of the embedded/encased stainless steel. After a review of the Browns Ferry operating history, the Browns Ferry Structures Monitoring Baseline inspection, and the results for the first Structures Monitoring inspection period did not reveal any loss of intended function due to aging effects for stainless steel that is embedded/encased within concrete. Operating history did show a small leak in the Unit 1 fuel pool liner. The Unit 1 fuel pool has remained in service during the extended outage since spent fuel is stored in the pool. This leak in the Unit 1 fuel pool was documented in accordance with the site's Corrective Action Program, SPP-3.1, Tennessee Valley Authority Nuclear (TVAN) Standard Program and Processes, "Corrective Action Program" as PER 00- 011982-000 (electronic corrective action program number 35486. This leak is contained within the leak channel beneath the fuel pool liner). The fuel pool liners are monitored on a monthly basis per operation instruction 1-OI-78. The leak is small (~0.06 gpm) and has been steady over time without an increasing trend over the last ten years.

The staff found the above applicant's justification reasonable and adequate because it was supported by the fact that the operating history, structures monitoring baseline inspection, and results from the first structures monitoring inspection period did not reveal any loss of intended function due to aging effects for aluminum and stainless steel embedded or encased within concrete. Therefore, the staff's concerns described in RAI 3.5-10 are resolved.

In RAI 3.5-14, dated December 10, 2004, the staff stated that, with respect to the neutron-absorbing sheets in spent fuel storage racks, as described in LRA Section 3.3.2.2, the applicant stated that the Chemistry Control Program manages general corrosion and that an inspection of Boral coupon test specimens was performed at BFN that confirmed that no significant aging degradation had occurred and that the neutron-absorbing capacity of the Boral had not been reduced. Since it is implied that some Boral aging degradations had occurred at the time of inspection of the test specimens, the staff requested the applicant to discuss the basis for the above assertion that the neutron-absorbing capacity of the Boral will be maintained at an adequate level during the extended period of plant operation.

In its response, by letter dated January 31, 2005, the applicant stated:

> A total of 16 boral coupons were placed in the Unit 3 spent fuel storage pool (SFSP) in October 1983. The coupons supplied by the rack manufacturer are of the same metallurgical condition as the high density fuel storage racks (HDFSR) in thickness, chemistry, finish, and temper. For the first six years of the planned fifteen year surveillance program, examination was to have taken place at two-year intervals. Accordingly, two coupons were removed in October 1985. Blisters were found upon examination, and because of this unexpected anomaly, three additional coupons were analyzed not finding any blisters. As a result of blisters found on the coupons removed in 1985, the surveillance program has been expanded to include monitoring the formation and behavior of these blisters. These boral coupons are periodically removed from the fuel pool for testing and are evaluated for corrosion or other degradation of the neutron absorber plates by comparing various physical characteristics of the test coupons to baseline measurements taken when the coupons were installed. Also, a metallurgical engineer examines the coupons for general corrosion, local pitting, and bonding. No further blisters, corrosion, or degradation has been identified in coupons evaluated through 2003.

The above response states that these Boral coupons are periodically removed from the fuel pool for testing and are evaluated for corrosion or other degradation of the neutron absorber plates by comparing various physical characteristics of the test coupons to baseline measurements taken when the coupons were installed. The response also implies that a metallurgical engineer periodically examines the coupons for general corrosion, local pitting, and bonding. Also, no further blisters, corrosion, or degradation have been identified in coupons evaluated through 2003; however, it was not clear to the staff whether these periodic inspections are ongoing activities that are an extension of the 1983 Boral Coupon Inspection Program covering Boral coupon test specimens or a separate AMP in addition to the Chemistry Control Program mentioned above. The applicant was requested to clarify the key parameters of this periodic inspection program or activity including the objective, scope, frequency, and inspection approach of the program.

In its response, by letter May 24, 2005, the applicant stated that:

> The Boral coupon inspection program was initiated in 1983 to implement the inspection and testing requirements of UFSAR Section 10.3.6; this checks the long-term behavior of the material of the high density spent fuel racks. The inspection is performed per BFN Technical Instruction (TI) TI-116, "High Density Fuel Storage System Surveillance Program." When the TI is performed, Boral coupons are removed from the spent fuel storage pool and examined by the Metallurgical Engineer in their original condition to determine if sampling of surface corrosion products is appropriate. Thickness measurements are obtained of each coupon and documented in accordance with the TI. If degradation is such that further investigation is warranted, a minimum of one coupon is selected to be unsheathed or opened. Prior to the unsheathing process, a dye penetrant test for indications on the outer surfaces of the coupon will be performed and is examined by the Metallurgical Engineer. The Metallurgical Engineer decides if further unsheathing of the coupons is required. The visual examination by the Metallurgical Engineer is documented on the appropriate forms of the TI. The current frequency for

performing this TI is two years. The surveillance frequency is re-evaluated each time the surveillance is performed and can be changed based on the trend of the historical data results. The inspection of the Boral coupons will continue until such time as the trend of the historical data results collected provides a basis to discontinue the inspections.

Based on its review, the staff found the applicant's response to RAI 3.5-14 acceptable. Therefore, the staff's concern described in RAI 3.5-14 is resolved.

In RAI 4.7.4-1, dated December 10, 2004, LRA Table 3.5.2.2 lists the AMR results of expansion joint (elastomer, polyurethane foam) as a TLAA and refers the TLAA to LRA Section 4.7. LRA Section 4.7.4, "Radiation Degradation of Drywell Expansion Gap Foam," states that an analysis of the effect of dose on the foam showed the material properties will remain within the limits assumed by the original design analysis for the additional 20 years of extended operation. Therefore, the staff requested the applicant to provide a more detailed discussion of the analysis including a discussion of the assumptions adopted in the analysis, the type of data extrapolation applied, and the quantitative results obtained to justify the assertion that the requirements of 10 CFR 54.21(c)(1)(i) are fully met.

By letter dated January 31, 2005, the applicant provided its response to RAI 4.7.4-1. The staff evaluation of the applicant's response is provided in SER Section 4.7.4.

In RAI 3.5-17, dated March 25, 2005, the staff stated that LRA Table 3.5.2.29, Radwaste Building, has three separate rows of component type listings (i.e., reinforced concrete, beams, column, walls, and slabs) which make references to note I,1 (last column of the table) and are shown to be associated with NUREG-1801 Section III.A3.1-h, Volume 2. Note I,1 of the table implies that the radwaste building is founded on rock or bearing piles. The note also refers to LRA Section 3.5.2.2.2.1 for further evaluation. Item 5 of the section does not clearly indicate that the radwaste building is founded on rock or bearing piles. Therefore, the staff requested that the applicant provide the type of foundation medium that supports the building; and if the structure is not founded on rock or piles, to discuss the basis for asserting that the cracking, distortion, and increase in component stress level due to settlement are not aging effects requiring management. The applicant was also asked, as appropriate, to revise LRA Sections 3.5.2.1 and 3.5.2.2.2.1 to include the radwaste building within the scope of its discussion.

In its response, by letter April 14, 2005, the applicant stated:

> The Radwaste Building is founded on piles as noted by the entry under "Component Type" - "Piles" in Table 2.4.7.8.
>
> LRA Section 3.5.2.2.2.1, Item 5, paragraph 1 on page 3.5-43 should be revised to read:
>
>> "Cracks, distortion, increase in component stress level due to settlement are not considered as aging effects requiring management for BFN structures founded on rock or bearing piles. The following BFN structures are founded on rock or bearing piles: Reactor Buildings, Primary Containments, Intake Pumping Station, Reinforced Concrete Chimney, Off-Gas Treatment Building, Equipment Access Lock, Turbine Buildings, Gate Structure Number 3, Diesel HPFP House, Transformer Yard, RHRSW Tunnel and Radwaste Building. Based on industry

experience, settlement of Class 1 structures founded on bedrock or bearing piles have not been noted to cause aging effects requiring management."

Based on its review, the staff found the applicant's response to RAI 3.5-17 acceptable. Therefore, the staff's concern described in RAI 3.5-17 is resolved.

In RAI 3.5-18, dated March 25, 2005, the staff stated that in its review of LRA Table 3.5.2.30, it was not clear as to whether the Group 5 category referred to includes the service building. Therefore, the staff requested that the applicant confirm that the service building, or portion of the service building, is clearly included within the scope addressed by LRA Section 3.5.2.2.2.1 and make any necessary revision to the LRA section to clarify its position.

In its response, by letter dated April 14, 2005, the applicant stated:

> The aging management review of the Service Building was performed to the requirements for Group 3 Structures of NUREG-1801, Vol. 2, Chapter III.A3. The Service Building is included within the scope addressed by LRA Section 3.5.2.2.2.1, Item 8 since it was considered as a Group 3 Structure and that section is applicable to Group 1 through Group 5 Structures of NUREG-1801, Vol. 2 Chapter 3.

The staff found the above response acceptable. Therefore, the staff's concern described in RAI 3.5-18 is resolved.

The staff also reviewed the information provided in LRA Section 3.5.2.1.2 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the reactor buildings' components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the service building components acceptable.

3.5.2.3.3 Equipment Access Lock – Summary of Aging Management Evaluation – Table 3.5.2.3

The staff reviewed LRA Table 3.5.2.3, which summarizes the results of AMR evaluations for the equipment access lock component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.3 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the equipment access lock components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the equipment access lock components acceptable.

3.5.2.3.4 Earth Berm – Summary of Aging Management Evaluation – Table 3.5.2.4

The staff reviewed LRA Table 3.5.2.4, which summarizes the results of AMR evaluations for the earth berm component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.4 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the earth berm components that are not addressed by the the

GALL Report. The staff found the applicant's AMR results for the earth berm components acceptable.

3.5.2.3.5 Diesel Generator Buildings – Summary of Aging Management Evaluation – Table 3.5.2.5

The staff reviewed LRA Table 3.5.2.5, which summarizes the results of AMR evaluations for the diesel generator buildings component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.25, for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

<u>Ceramic Fiber in an Inside Air Environment</u> - The staff requested that the applicant provide the BFN technical basis for concluding that no aging management is required for ceramic fiber fire barriers in an inside air environment.

The following list identifies ceramic fiber components in an inside air environment:

- reactor building fire barriers
- diesel generator building fire barriers

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that ceramic and glass fiber used to seal fire barrier penetrations do not have any applicable aging effects requiring aging management. This is consistent with previous staff positions in LRA SER concurrences that there are no applicable aging effects for glass used in a metal fire barrier penetration. This is also consistent with the NUREG-1769 SER related to the license renewal of another plant which concurred that insulation made of aluminum, stainless steel (mirror), calcium silicate, ceramic fiber, or fiberglass in a sheltered environment does not have any aging effects requiring aging management.

The applicant further stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for the following ceramic fiber components.

- reactor building fire barriers
- diesel generator building fire barriers

The staff concluded that the applicant had not credited an existing AMP (structures monitoring and/or fire protection) that already included fire barriers in its scope on the basis that its AMR did not identify any applicable aging effects.

The staff's review of LRA Table 3.5.2.5 identified an area in which additional information was necessary to complete the review of the applicant's results. The applicant responded to the staff's RAI, as discussed below.

In RAI 3.5-11, dated December 10, 2004, the staff stated that, with respect to the fire barriers consisting of ceramic fiber listed in LRA Table 3.5.2.5, the applicant's AMR identified neither AERM nor AMP for the ceramic fiber fire barriers. Therefore, the staff requested that the applicant discuss past plant-specific inspection results of these fire barriers in order to provide an operating experience-based justification for the above AMR finding.

In its response, by letter dated January 31, 2005, the applicant stated:

> *This same RAI was asked as RAI 3.3-2 for the Reactor Building. In the response to that RAI, the same material was also addressed for the Diesel Generator Building (Table 3.5.2.5, item number 10 on page 3.5-74). Refer to the TVA response to RAI 3.3-2 (TVA letter to NRC dated September 30, 2004).*

The staff found the response to RAI 3.5-11 provided in SER Section 3.3 acceptable; therefore, the staff's concern expressed in RAI 3.5-11 is resolved.

The staff also reviewed the information provided in LRA Section 3.5.2.1.5 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the diesel generator buildings' components that are not addressed by the GALL Report. The staff found the applicant's AMR results for diesel generator buildings' components acceptable.

3.5.2.3.6 Standby Gas Treatment Building – Summary of Aging Management Evaluation – Table 3.5.2.6

The staff reviewed LRA Table 3.5.2.6, which summarizes the results of AMR evaluations for the standby gas treatment building component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.6 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the standby gas treatment building components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the standby gas treatment building components acceptable.

3.5.2.3.7 Off-Gas Treatment Building – Summary of Aging Management Evaluation – Table 3.5.2.7

The staff reviewed LRA Table 3.5.2.7, which summarizes the results of AMR evaluations for the off-gas treatment building component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.7 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the off-gas treatment building components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the off-gas treatment building components acceptable.

3.5.2.3.8 Vacuum Pipe Building – Summary of Aging Management Evaluation – Table 3.5.2.8

The staff reviewed LRA Table 3.5.2.8, which summarizes the results of AMR evaluations for the vacuum pipe building component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.8 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the vacuum pipe building components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the vacuum pipe building components acceptable.

3.5.2.3.9 Residual Heat Removal Service Water Tunnels – Summary of Aging Management Evaluation – Table 3.5.2.9

The staff reviewed LRA Table 3.5.2.9, which summarizes the results of AMR evaluations for the RHRSW tunnels' component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.9 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the RHRSW tunnel components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the RHRSW tunnel components acceptable.

3.5.2.3.10 Electrical Cable Tunnel from Intake Pumping Station to the Powerhouse – Summary of Aging Management Evaluation – Table 3.5.2.10

The staff reviewed LRA Table 3.5.2.10, which summarizes the results of AMR evaluations for the electrical cable tunnel from intake pumping station to the powerhouse component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.10 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the electrical cable tunnel from the intake pumping station to the powerhouse components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the electrical cable tunnel from the intake pumping station to the powerhouse components acceptable.

3.5.2.3.11 Underground Concrete Encased Structures – Summary of Aging Management Evaluation – Table 3.5.2.11

The staff reviewed LRA Table 3.5.2.11, which summarizes the results of AMR evaluations for the underground concrete-encased structures component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.11 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the underground concrete-encased structures components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the underground concrete encased structures' components acceptable.

3.5.2.3.12 Intake Pumping Station – Summary of Aging Management Evaluation – Table 3.5.2.12

The staff reviewed LRA Table 3.5.2.12, which summarizes the results of AMR evaluations for the intake pumping station component groups.

In LRA Table 3.5.2.12, the applicant stated that no aging management is required for submerged reinforced concrete. Plant-specific Note 5 states that for cracking, loss of bond, loss of material (spalling, scaling) due to corrosion of embedded steel in concrete for inaccessible areas, no plant-specific aging management is required. Plant-specific Note 6 states that, for increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack of concrete for inaccessible areas, no plant-specific aging management is required.

During the onsite audit, the staff reviewed other selected items in LRA Table 3.5.2.12, for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

<u>Reinforced Concrete in a Submerged Environment</u> - In LRA Table 3.5.2.12 (Intake Pumping Station - Summary of Aging Management Evaluation), rows 37 and 38, the applicant stated that no aging management is required for submerged reinforced concrete. Note 5 for row 37 states that for cracking, loss of bond, loss of material (spalling, scaling) due to corrosion of embedded steel in concrete for inaccessible areas, no plant-specific aging management is required. Note 6 for row 38 states that for increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack of concrete for inaccessible areas, no plant-specific aging is required.

The staff noted that a submerged component is not necessarily inaccessible. If the submerged component is accessible, it is expected that the component will be managed by the Inspection of Water Control Structures Program. The staff requested that the applicant identify all the submerged concrete components in the intake pumping station, and provide the technical basis for designating these components as being inaccessible. The staff also requested that the applicant identify all the submerged concrete structures that will be inspected under Water Control Structures Program, and describe the implementing details of the inspection of submerged structures included in the Water Control Structures Program.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that:

> Browns Ferry groundwater water and Wheeler Reservoir water sample measurements presented in the response to question 297 have confirmed that parameters are well below threshold limits that could cause concrete degradation (an aggressive environment does not exist). It is not credible to postulate that some environmental event will occur in the future that would affect the quality of groundwater in the vicinity of Browns Ferry. A change in the environment due to a chemical release would be considered as an "abnormal event". NUREG-1800, "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," states that aging effects from abnormal events need not be postulated specifically for license renewal.

In-scope submerged concrete exposed to Wheeler Reservoir water is not readily accessible for inspection. Several in-scope submerged concrete common areas outside of individual pump bays where continuous flow make diver entry unsafe would require a multiple unit outage to inspect. Browns Ferry will perform a one time inspection of the in-scope submerged concrete in one individual pump bay to confirm the absence of aggressive environmental aging effects and that a loss of intended function has not occurred due to aggressive environment aging effects.

Browns Ferry will also continue to perform periodic inspections of accessible concrete in an inside air environment and outside air environment for in-scope structures with the Structures Monitoring Program.

The staff concluded that the applicant's AMR is not consistent with the GALL Report and is not acceptable, because there is no commitment to conduct periodic inspection of accessible, submerged water control concrete structures. This issue was addressed in RAI 3.5-16 and is discussed below.

In RAI 3.5-16, dated March 11, 2005, the staff requested the applicant to demonstrate that the groundwater is not an aggressive environment, although the facts show that an aggressive environment does not exist for groundwater, and continuous water flow in several in-scope submerged concrete common areas outside of individual pump bays makes diver entry unsafe. Therefore, the staff requested that the applicant provide the following additional information and a plant-specific commitment, as needed, in order to expedite staff closure of the issue raised by the audit team:

(1) A discussion of past inspection findings, and repairs and maintenance experience for submerged, reinforced concrete structures (e.g., intake structure).

(2) A discussion of the pertinent submerged, reinforced concrete test data (as available) which demonstrate that the conditions stated in the discussion columns of items III A6.1-b and III A6.1-d in GALL Report, Volume II, are fully met.

(3) A detailed description of the one-time inspection by the applicant, cited above, of the in-scope submerged concrete in one individual pump bay, including method of inspection; concrete elements and parameters or types of degradation to be inspected; criteria for judging the observed types, extent, and severity of reinforced concrete degradation that would trigger BFN's commitment to an AMP for submerged concrete with a periodic inspection provision, inspection frequency, and schedule for implementing the One-Time Inspection Program.

(4) A discussion of the methods (e.g., regular monitoring of the raw water for pH, chloride concentration, sulfate concentration, abrasive particulates, detrimental organic agents) that will be employed to ensure that the raw service water in close proximity to the intake structure remains non-aggressive to the submerged concrete during the extended period of operation.

In its response, by letter dated April 5, 2005, the applicant stated:

(1) BFN's submerged concrete operating experience:

A baseline inspection for the BFN Structures Monitoring Program was established in 1997 and included the Intake Pumping Station and Gate Structure No. 3. Baseline inspections and subsequent BFN Structures Monitoring Program inspections included accessible interior and exterior concrete surfaces of the Intake Pumping Station and Gate Structure No. 3. Only the Intake Pumping Station has submerged concrete that is in the scope of license renewal. Although the Intake Pumping Station submerged concrete was not inspected, there is reasonable assurance that the submerged concrete results would be consistent due to a lack of an aggressive environment and use of the same concrete specifications for the construction as the accessible portions of the Intake Pumping Station.

Defect evaluations performed since the baseline inspection and subsequent inspections are documented in the 2002 Structures Monitoring Program results. Below is a highlight of plant-specific operating experience for concrete elements at the Intake Pumping Station and Gate Structure No. 3. None of the identified indications were considered significant or affected the function of the structure.

- Intake Pumping Station: Very minor concrete surface cracks
- Gate Structure No. 3: Very minor concrete surface cracks and spalling

Additionally, to capture plant operating experience for these structures, work orders (WOs), the site Correction Action Program and site Licensing Event Reports (LERs) were reviewed for various operating periods:

- Work Orders between 1991 and 2004 were reviewed to determine if any corrective maintenance or repairs were performed on the Intake Pumping Station (IPS). A total of 2633 WOs were reviewed for that period and no work activities were found involving the submerged concrete for this structure.
- The site's Correction Action Program was reviewed for the IPS to identify any adverse conditions of the structure, with emphasis on the submerged concrete. A total of 1790 reports were reviewed for a time period between 1994 and 2004, with none being identified for the IPS submerged concrete.
- Licensing Event Reports were reviewed for a period between 1985 and 2004 and none were identified affecting the IPS.

(2) GALL conditions for III A6.1-b (increase in porosity and permeability, loss of strength due to leaching of calcium hydroxide)& III A6.1-d (cracking, loss of bond, loss of material (spalling, scaling) due to corrosion of embedded steel):

See further evaluations in LRA Section 3.5.2.2.2.1, item 2 and LRA Section 3.5.2.2.2.2 for discussion on these issues.

(3) Submerged concrete one-time inspection:

The following elements apply to the one-time inspection for submerged concrete:

a. Scope of One-Time Inspection:

   In-scope submerged concrete in one individual pump bay of the Intake Pumping Station. The submerged concrete surfaces will be inspected.

b. Preventative Measures:

   The one-time inspection specifies no preventive actions.

c. Parameters Monitored or Inspected:

   The following concrete aging effects will be inspected during the one-time inspection of submerged concrete at the intake pumping station (IPS).

   - Increase in porosity and permeability, and loss of strength due to leaching of calcium hydroxide
   - Expansion and cracking due to reaction with aggregates
   - Cracking, loss of bond, and loss of material (spalling, scaling) due to corrosion of embedded steel
   - Increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack

   The Intake Pumping Station will be periodically inspected for loss of material (spalling, scaling)and cracking due to the effects of freeze-thaw at the waterline where icing conditions could occur(see GALL audit question 368). The periodic inspection for aging effects due to freeze thaw will be included in the BFN Structures Monitoring Program.

d. Detection of Aging Effects:

   Visual inspections of structural conditions will be used as the method used to detect aging effects. An inspection checklist consistent with those used for Structures Monitoring Program will be used. All defects will be required to be identified and documented on the inspection checklists for review and evaluation by the Responsible Engineer (BFN Structures Monitoring Program Engineer). Individuals trained and experienced with the BFN Structures Monitoring Program will perform the inspections.

e. Monitoring and Trending:

   The submerged concrete at the Intake Pumping Station will be inspected prior to the extended period of operation.

f. The acceptance criteria of the BFN Structures Monitoring Program will be used. BFN Structures Monitoring Program acceptance criteria are based upon Responsible Engineer (BFN Structures Monitoring Program Engineer) review and classification of the results as acceptable, acceptable with deficiencies, and unacceptable respectively. These performance criteria ensure that the structure:

- remains capable of meeting its design basis and performing its intended function; and
- will not result in a loss of intended function due to a degraded condition or aging effect.

If the submerged concrete fails to meet the acceptance criteria, a cause determination evaluation will be performed. If acceptance criteria are not meet, two additional pump bays will be inspected prior to the extended period of operation. If one or more of the additional pump bays fails to meet its acceptance criteria, then submerged concrete at the intake pump station will be inspected periodically consistent with the Structures Monitoring Program requirements.

(4) Periodic monitoring of raw service water:

Prior to entering the period of extended operation, BFN will initiate periodic monitoring of the raw service water in close proximity to the Intake Pumping Station for the requirements of an aggressive environment as described in NUREG-1557. Periodic monitoring will be consistent with the BFN Structures Monitoring Program inspection frequency.

The staff reviewed the above response and found that the applicant fully had responded to RAI 3.5-16 with reasonable plant operation-based justifications. Therefore, the staff's concern described in RAI 3.5-16 is resolved.

Aluminum in an Outside Air Environment – The staff requested the applicant to provide the technical basis for concluding that no aging management of aluminum components is required for an outside environment.

The following list identifies aluminum components in an outside air environment:

- electrical and I&C penetrations
- conduits and supports
- non-ASME equivalent supports

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that aluminum alloys containing zinc are susceptible to corrosion in wetted, aggressive environments. The outside air environment does not have contaminants that would cause an aggressive environment. Additionally, rain would periodically wash any contaminant(s) from the material. The aluminum penetration sleeves and conduit at BFN are also constructed of 6063-T42 alloy material that is resistant to pitting, crevice corrosion, and SCC (Metals Handbook, Ninth Edition, Volume 13, "Corrosion," ASM International, 1987). Therefore, the potential for concentration of contaminates is not significant for aluminum components in an outside air environment and loss of function due to corrosion is not considered plausible.

The applicant also stated that EPRI structural tools document, "Aging Effects for Structures and Structural Components (Structural Tools)," EPRI 1002950 revision 1, August 2003, states that aging management is not required for structural aluminum and aluminum alloys in a non-aggressive ambient outside environment (general, galvanic, crevice and pitting corrosion, and SCC).

The applicant further stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for the following aluminum components:

- electrical and I&C penetrations
- conduits and supports
- non-ASME equivalent supports

The staff accepts the applicant's AMR results, that aging management is not required for these aluminum components in an outside environment, on the basis that (1) the material used is resistant to corrosion and SCC, and (2) concentration of contaminates in a non-aggressive ambient outside environment is not plausible

The staff also reviewed the information provided in LRA Section 3.5.2.1.12 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the intake pumping station components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the intake pumping station components acceptable.

3.5.2.3.13 Gate Structure No. 3 – Summary of Aging Management Evaluation – Table 3.5.2.13

The staff reviewed LRA Table 3.5.2.13, which summarizes the results of AMR evaluations for the gate structure No. 3 component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.13 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the gate structure No. 3 components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the gate structure No. 3 components acceptable.

3.5.2.3.14 Intake Channel – Summary of Aging Management Evaluation – Table 3.5.2.14

The staff reviewed LRA Table 3.5.2.14, which summarizes the results of AMR evaluations for the intake channel component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.14 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the intake channel components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the intake channel components acceptable.

3.5.2.3.15 North Bank of Cool Water Channel East of Gate Structure No. 2 – Summary of Aging Management Evaluation – Table 3.5.2.15

The staff reviewed LRA Table 3.5.2.15, which summarizes the results of AMR evaluations for the north bank of cool water channel east of gate structure No. 2 component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.15 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the north bank of cool water channel east of gate structure No. 2 components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the north bank of cool water channel east of gate structure No. 2 components acceptable.

3.5.2.3.16 South Dike of Cool Water Channel Between Gate Structure Nos. 2 and 3 – Summary of Aging Management Evaluation – Table 3.5.2.16

The staff reviewed LRA Table 3.5.2.16, which summarizes the results of AMR evaluations for the south dike of cool water channel between gate structure Nos. 2 and 3 component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.16 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the south dike of the cool water channel between gate structure Nos. 2 and 3 components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the south dike of the cool water channel between gate structure Nos. 2 and 3 components acceptable.

3.5.2.3.17 Condensate Water Storage Tanks' Foundations and Trenches – Summary of Aging Management Evaluation – Table 3.5.2.17

The staff reviewed LRA Table 3.5.2.17, which summarizes the results of AMR evaluations for the condensate water storage tanks' foundations and trenches component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.17, for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 item:

Earthfill & Rock in a Buried Environment - This item indicates that the equipment supports and foundations are earth fill (rock and sand). The staff requested that the applicant explain the technical bases for concluding that there are no aging effects requiring management.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that the foundation for the CWST is comprised of a concrete ring foundation with the interior portion of the ring foundation filled with crushed rock and sand. The earthen materials (rock and sand) of the CWST foundation interior base are protected from environmental weathering conditions by the concrete perimeter ring and CWST tank bottom. There are no aging effects for the earthen materials of the CWST foundation interior base that require aging management. Aging management of the CWST concrete foundation ring is managed by the Structures Monitoring Program. Aging management of the CWST bottom will be performed by the One-Time Inspection Program.

The applicant also stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for earthen materials of the CWST foundation interior base.

Based on the additional information provided by the applicant, the staff concurs with the applicant's AMR results for the crushed rock and sand base of the CWST. The staff concluded that aging management is not required because these materials are adequately protected by the concrete perimeter ring and the CWST tank bottom.

The staff also reviewed the information provided in LRA Section 3.5.2.1.17 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the condensate water storage tanks' foundations and trenches components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the condensate water storage tanks' foundations and trenches components acceptable.

3.5.2.3.18 Containment Atmosphere Dilution Storage Tanks' Foundations – Summary of Aging Management Evaluation – Table 3.5.2.18

The staff reviewed LRA Table 3.5.2.18, which summarizes the results of AMR evaluations for the containment atmosphere dilution storage tanks' foundations component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.18 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the containment atmosphere dilution storage tanks' foundations components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the containment atmosphere dilution storage tanks' foundations components acceptable.

3.5.2.3.19 Reinforced Concrete Chimney – Summary of Aging Management Evaluation – Table 3.5.2.19

The staff reviewed LRA Table 3.5.2.19, which summarizes the results of AMR evaluations for the reinforced concrete chimney component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.19 for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

<u>Carbon Steel in a Buried Environment</u>- The applicant stated that the Structures Monitoring Program relies on visual inspections whenever the components are uncovered during station yard area excavations. The staff requested that the applicant confirm that this applies to buried mechanical penetrations, clarify what other components are included in this provision, and explain whether this is an enhancement to the existing program or whether this provision is covered in the current program.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LCEI-CI-C9 will be enhanced to include inspection of mechanical penetrations when accessible. There are no other buried carbon steel components included with the program; however, LCEI-CI-C9 will also be enhanced to include the inspection of buried concrete when accessible. With enhancements, LCEI-CI-C9 will be consistent with GALL AMP XI.S6.

The applicant also stated that the Buried Piping and Tanks Inspections Program provides the inspection requirements of buried piping when accessible. The Buried Piping and Tanks Inspections Program is consistent with GALL AMP XI.M34. Section 7.2.9.2 of LCEI-CI-C9 currently provides the inspection attributes of buried piping, which includes pipe connections and joints, and is credited as the Buried Piping and Tanks Inspections Program.

The staff concluded that the applicant's commitment to enhance the Structures Monitoring Program to include inspection of buried mechanical penetrations when accessible, provides a level of aging management for buried mechanical penetrations that is comparable to the GALL Report recommendations for buried concrete, piping and tanks. Therefore, the staff found this acceptable.

The staff also reviewed the information provided in LRA Section 3.5.2.1.19 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the reinforced concrete chimney components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the reinforced concrete chimney components acceptable.

3.5.2.3.20 Turbine Buildings – Summary of Aging Management Evaluation – Table 3.5.2.20

The staff reviewed LRA Table 3.5.2.20, which summarizes the results of AMR evaluations for the turbine buildings component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.20 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects, for the turbine buildings components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the turbine buildings components acceptable.

3.5.2.3.21 Diesel High Pressure Fire Pump House – Summary of Aging Management Evaluation – Table 3.5.2.21

The staff reviewed LRA Table 3.5.2.21, which summarizes the results of AMR evaluations for the diesel high-pressure fire pump house component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.21 for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 item:

Stainless Steel in a Submerged Environment - This item credits the Structures Monitoring Program for managing the effects of loss of material due to crevice corrosion and pitting corrosion for stainless steel beams, columns, plates, and trusses in a submerged environment. The staff requested the applicant to identify (1) the components included in this item and (2) where they are located, and (3) the submerged environment. A description of the types of inspections that will be performed under the Structures Monitoring Program for these components and clarification on whether these inspections are included in the current scope of the Structures Monitoring Program was also requested. The staff also requested the applicant to provide the technical basis for not monitoring water chemistry.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Table 3.5.2.21 row 28 applies to submerged portions of the stainless steel debris screen under the diesel high pressure fire pump house. The intended functions of the debris screen are debris protection and NSR structural support. The applicant also stated that the miscellaneous components portion of the Structures Monitoring Program will be enhanced to visually inspect the submerged portions of the debris screen for loss of material due to crevice and pitting corrosion. The applicant noted that portions of the diesel high-pressure fire pump house debris screen are submerged in a raw water environment; therefore, monitoring of water chemistry is not applicable as an AMP.

The staff accepts the applicant's commitment to enhance the Structures Monitoring Program to visually inspect the submerged portions of the stainless steel debris screen for loss of material due to crevice and pitting corrosion. The staff considered this to be analogous to submerged portions of water control structures for which visual inspection conducted as part of the Structures Monitoring Program has been previously accepted.

The staff also reviewed the information provided in LRA Section 3.5.2.1.21 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the diesel high-pressure fire pump house components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the diesel high-pressure fire pump house components acceptable.

3.5.2.3.22 Vent Vaults – Summary of Aging Management Evaluation – Table 3.5.2.22

The staff reviewed LRA Table 3.5.2.22, which summarizes the results of AMR evaluations for the vent vaults component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.22 and determined that the applicant had adequately identified applicable aging effects and the AMPs credited for managing the aging effects for the vent vaults components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the vent vaults components acceptable.

3.5.2.3.23 Transformer Yard – Summary of Aging Management Evaluation – Table 3.5.2.23

The staff reviewed LRA Table 3.5.2.23, which summarizes the results of AMR evaluations for the transformer yard component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.23 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the transformer yard components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the transformer yard components acceptable.

3.5.2.3.24 161 kV Switchyard – Summary of Aging Management Evaluation – Table 3.5.2.24

The staff reviewed LRA Table 3.5.2.24, which summarizes the results of AMR evaluations for the 161 kV switchyard component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.24 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the 161 kV switchyard components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the 161 kV switchyard components acceptable.

3.5.2.3.25 500 kV Switchyard – Summary of Aging Management Evaluation – Table 3.5.2.25

The staff reviewed LRA Table 3.5.2.25, which summarizes the results of AMR evaluations for the 500 kV Switchyard component groups.

The staff also reviewed the information provided in LRA Section 3.5.2.1.25 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the 500 kV switchyard components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the 500 kV switchyard components acceptable.

3.5.2.3.26 Structures and Component Supports – Summary of Aging Management Evaluation – Table 3.5.2.26

The staff reviewed LRA Table 3.5.2.26, which summarizes the results of AMR evaluations for the structures and component supports component groups.

During the onsite audit, the staff reviewed selected items in LRA Table 3.5.2.26 for MEAP combinations that are not consistent with the GALL Report. The staff requested clarifications for the following material/environment combinations and the corresponding LRA Table 2 items:

Aluminum in an Inside Air Environment - The staff requested the applicant to provide the technical basis for concluding that no aging management of aluminum supports is required for loss of mechanical function in an inside air environment.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that aluminum in an inside air environment applies to aluminum pipe lugs for equivalent ASME Class 2 or 3 piping in the reactor buildings (inside air environment). Aluminum external surfaces are not susceptible to corrosion unless their surfaces are wetted and there is a potential for concentration of contaminants. The aluminum pipe lugs in the reactor building are not exposed to a wetted aggressive/corrosive environment. Therefore, the potential for concentration of contaminants is not significant for aluminum components in an inside air environment and loss of mechanical function due to corrosion is not considered plausible.

The applicant further stated that EPRI structural tools document, "Aging Effects for Structures and Structural Components (Structural Tools)" EPRI 1002950 Revision 1, August 2003, states that aging management is not required for structural aluminum and aluminum alloys in an inside environment (general, galvanic, crevice, pitting corrosion, and SCC).

The applicant also stated that a review of BFN operating history did not reveal any loss of intended function due to aging effects for aluminum pipe lugs for equivalent ASME Code Class 2 or 3 piping in the reactor buildings for an inside air environment.

The staff found that the applicant had not considered loss of mechanical function due to aging mechanisms other than corrosion. This omission is not consistent with the GALL Report. The applicant also failed to credit an existing AMP (IWF) that includes the subject components in its scope.The staff requested additional information to resolve this issue, and related issues. The disposition is discussed at the end of this section, as part of the review of LRA Table 3.5.2.26 AMRs.

The staff also reviewed the information provided in LRA Section 3.5.2.1.26 and determined that the applicant had adequately identified applicable aging effects, and the AMPs credited for managing the aging effects for the structures and component supports commodities components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the structures and component supports commodities components acceptable.

Aluminum in an Outside Air Environment – The staff requested the applicant to provide the technical basis for concluding that no aging management of aluminum components is required for an outside environment.

The following list identifies aluminum components in an outside air environment:

- electrical and I&C penetrations
- conduits and supports
- non-ASME equivalent supports

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that aluminum alloys containing zinc are susceptible to corrosion in wetted aggressive environments. The outside air environment does not have contaminants that would cause an aggressive environment. Additionally, rain would periodically wash any contaminant(s) from the material. The aluminum penetration sleeves and conduit at BFN are also constructed of 6063-T42 alloy material that is resistant to pitting, crevice corrosion, and SCC (Metals Handbook, Ninth Edition, Volume 13, "Corrosion," ASM International, 1987). Therefore, the potential for concentration of contaminates is not significant for aluminum components in an outside air environment and loss of function due to corrosion is not considered plausible.

The applicant also stated that EPRI structural tools document, "Aging Effects for Structures and Structural Components (Structural Tools)" EPRI 1002950 Revision 1, August 2003, states that aging management is not required for structural aluminum and aluminum alloys in a non-aggressive ambient outside environment (general, galvanic, crevice and pitting corrosion, and SCC).

The applicant further stated that a review of Browns Ferry operating history did not reveal any loss of intended function due to aging effects for the following aluminum components:

- electrical and I&C penetrations
- conduits and supports
- non-ASME equivalent supports

The staff accepts the applicant's AMR results, that aging management is not required for these aluminum components in an outside environment, on the basis that (1) the material used is resistant to corrosion and SCC, and (2) concentration of contaminates in a non-aggressive ambient outside environment is not plausible

Carbon Steel in a Containment Air Environment – For the high-strength bolts included under this item, the staff requested that the applicant describe the bolting material, the nominal and as-built yield strengths, and the hardness of the material. The applicant was also requested to discuss the disposition of the recommendations for a comprehensive Bolting Integrity Program, as delineated in NUREG-1339, and industry recommendations, as delineated in EPRI NP-5769.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating:

> The only high strength structural bolting (ultimate tensile strength [UTS] > 150 ksi) material specified for use at BFN is ASTM A-490 (Ref. General Engineering Specification G-29BS01, PS 4.M.4.4, "ASME Section III and Non-ASME Section III (including AISC, ANSI B31.1, and ANSI B31.5) Bolting Material"). The ultimate tensile strength for A-490 bolting ½" to 1 ½" may vary between 150 to 170 ksi, a minimum yield strength of 130 ksi is specified and hardness may vary from 33 to 38 Rockwell C (ASTM A-490 Standard).
>
> The Bolting Integrity Program manages loss of material of mechanical component steel bolting within the scope of License Renewal. ASME Section XI manages aging of structural bolting (encompassed by 'Support members; welds; bolted connections; support anchorage to building structure') for ASME equivalent supports. Structures Monitoring Program manages aging of structural bolting for the remaining structural supports within the scope of License Renewal. The support components, including the bolting, are periodically inspected for loss of material by these programs.
>
> High strength bolting (UTS >150 ksi) is not considered susceptible to cracking due to stress corrosion cracking at BFN. For SCC to manifest in high strength bolting, an aggressive chemical or wetted environment is required in addition to susceptible material and high tensile stresses. High strength bolting (UTS >150 ksi) used in ASME equivalent supports at BFN are installed in indoor air environments that are not exposed to aggressive chemicals, periodic wetting, or splash zones. Additionally, high strength bolting is used for Unit 1 drywell floor steel framing and other structural purposes to connect the RPV skirt flange to the top flange of the ring girder in the drywell and these bolts are exposed to a containment atmosphere environment in the drywell not subject to aggressive chemicals, periodic wetting or splash zones. As noted below, thread lubricants are also controlled to eliminate corrosive environmental effects. Therefore an aggressive chemical or wetted environment does not exist.
>
> Per the EPRI Mechanical and Structural Tools and EPRI NP-5769, high strength bolting is considered susceptible to SCC in a corrosive environment with the use of thread lubricants containing molybdenum disulfide. Approved thread lubricants for use in bolted joints at BFN are specified in General Engineering Specification (GES) G-29B-S01 PS 4.M.1.1 and Section 3.9.2 notes that lubricants containing molybdenum disulfide shall not be used.
>
> Structural bolting procurement activities, receipt inspection and installation (torquing), as defined in TVA procedure GES G-29B-S01, P.S.4.M.4.4, 'ASME Section III and Non-

Section III (Including AISC, ANSI B31.1, and ANSI B31.5) Bolting Material', are considered part of TVA's Bolting Integrity Program and meet the industry recommendations for these activities as delineated in NUREG-1339 and EPRI NP-5769.

The staff found that the applicant had presented a sufficient technical basis to support its AMR results that high-strength bolting used in structural applications is not susceptible to SCC. The staff determined that meeting the recommendations delineated in NUREG-1339 and EPRI NP-5769 provides reasonable assurance that SCC will not occur.

Carbon Steel in an Inside Air Environment - The applicant indicated that only loss of material due to general corrosion and loss of mechanical function due to corrosion are considered applicable aging effects for the subject ASME-equivalent supports. The staff requested the applicant to provide the technical basis for concluding that other aging mechanisms are not applicable.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.26 row 2 applies to ASME-equivalent Class 1 supports. The AMR for the material and environment combination of carbon steel in an inside air environment was performed and the applicant concluded that the only plausible aging mechanisms needing managing were:

- loss of material due to general corrosion
- loss of mechanical function due to corrosion, distortion, dirt, overload, and fatigue due to vibratory and cyclic thermal loads

The applicant further stated that ASME Section XI, Subsection IWF will be used to manage these aging effects of loss of material and loss of mechanical function identified in Table 3.5.2.26 row 2. The staff found this acceptable, because it is consistent with GALL.

Carbon Steel in an Outside Air Environment– The applicant indicated that only loss of material due to general corrosion, crevice corrosion, and pitting corrosion are considered applicable aging effects for the subject ASME-equivalent supports. The staff requested the applicant to provide the technical basis for concluding that other aging mechanisms are not applicable.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.26, row 9 applies to ASME-equivalent Class 2 and 3 supports. The AMR for the material/environment combination of carbon steel in an outside air environment was performed and the applicant concluded that the only plausible aging mechanism that needed to be managed was loss of material due to general, crevice, and pitting corrosion.

The applicant further stated that the ASME Code Section XI, Subsection IWF will be used to manage the aging effect of loss of material identified in Table 3.5.2.26, row 9.

The staff noted that loss of mechanical function is also managed by IWF, even though the applicant did not identify this aging effect. The staff accepts the applicant's AMR results solely on the basis that IWF is credited for license renewal, and IWF will manage loss of mechanical function in addition to loss of material.

The applicant also stated that the referenced table row applies to ASME-equivalent Class 2 and 3 supports and is not applicable to Class MC supports, and that the response to RAI-3.5-6 will address the AMR results for Class MC supports.

Carbon Steel in a Submerged Environment – The staff requested that the applicant identify (1) the components included in this item, (2) where they are located, and (3) the submerged environment. The staff also requested the applicant to provide the technical basis for not including these component types in the One-Time Inspection Program to confirm the effectiveness of the Chemistry Control Program.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.26, row 57 applies to carbon steel non-ASME Code equivalent supports inside the CWST. Aging of carbon steel supports submerged in the CWST (treated water environment) will be managed through monitoring CWST water chemistry by the Chemistry Control Program. Effectiveness of the CWST Chemistry Control Program will be confirmed by the One-Time Inspection Program of carbon steel mechanical components in a treated water (condensate water) environment as noted in LRA Table 3.4.2.2 (Condensate and Demineralized Water System).

The staff found the use of the Chemistry Control Program and confirmation by the One-Time Inspection Program acceptable to manage aging of submerged supports inside the condensate water storage tank, on the basis that the supports are treated as part of the tank in the applicant's AMR.

Lubrite in an Inside Air Environment - The staff requested that the applicant describe where the referenced items are used and provide the technical basis for concluding that no aging management of the lubrite plates used in BFN is required in an inside air environment.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.26, row 35 applies to the lubrite plates used for the core spray and RHR pump/equipment base supports. EPRI 1002950, "Aging Effects for Structures and Structural Components (Structural Tools), Revision 1," August 2003, states that lubrite material 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. Lubrite products are solid, permanent, completely self lubricating, and require no maintenance. The reactor building environment at the location of the core spray and RHR pump equipment base supports is not an aggressive or wetted environment.

The applicant also stated that a search of BFN and industry operating experience did not identify any instances of lubrite plate degradation or failure to perform its intended function due to aging effects. NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4," and NUREG-1769, "Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3," concur that there are no lubrite plate aging effects that require aging management.

Based on the additional information provided by the applicant, the staff found the applicant's AMR results for lubrite plates to be acceptable. Prior staff evaluations of this issue have concluded that there are no aging effects requiring aging management.

Reinforced Concrete in a Buried Environment - This item applies to buried reinforced concrete equipment supports and foundations. The staff requested that the applicant explain how the Structures Monitoring Program is used to manage these buried (presumably inaccessible) components.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that Table 3.5.2.26, row 41 applies to transformer pads/foundations in the transformer yard, 161kV switchyard and 500kV switchyard in a buried environment. The electrical equipment concrete foundations are exposed to both the outside air environment and the inaccessible buried environment. The outside air environment is addressed in LRA Table 3.5.2.26, row 44. Reduction in concrete anchor capacity will manifest itself at the anchor locations which are located in the outside air environment. The Structures Monitoring Program will manage reduction of concrete anchor capacity for those portions of the equipment foundations exposed to the outside air environment. Aging management for below grade inaccessible concrete will be based on inspection of the accessible concrete in the outside air environment.

Based on the additional information provided by the applicant, the staff found the applicant's AMR results for the buried portions of the concrete transformer pads/foundations to be acceptable. Periodic inspection of the accessible concrete by the Structures Monitoring Program will provide an indication of the condition of the buried concrete.

Stainless Steel in a Submerged Environment - The staff requested the applicant to identify (1) the ASME-equivalent supports and components included in this item, (2) where they are located, and (3) the submerged environment. The applicant was also requested to provide the BFN AMR for this item and discuss the technical basis for not crediting ASME Section XI, Subsection IWF as the AMP.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that LRA Table 3.5.2.26, row 11 applies to the stainless steel ASME-equivalent Class 2 supports for the safety-related valve (SRV) discharge lines that are in the submerged environment of the suppression pool water. The Chemistry Control Program and a one-time inspection will manage loss of material for stainless steel ASME-equivalent Class 2 supports exposed in a submerged treated (suppression pool) water environment. These lines are exempt from inspection per ASME Section XI.

Based on the additional information provided by the applicant, the staff accepts the applicant's AMR results for stainless steel ASME Code equivalent Class 2 supports for the SRV discharge lines that are in the submerged environment of the suppression pool water. The staff concurred that these supports are exempt from IWF inspection because they are not fluid filled. The credited AMPs are consistent with the GALL Report recommendations for Class 1 stainless steel small-bore piping. The staff found this appropriate, in lieu of IWF.

LRA Table 3.5.2.26 - In LRA Table 3.5.2.26, rows 5, 6, 10, 14, 15, 16, and 18, the applicant indicated that no aging management is required in containment atmosphere, inside air and outside air environments for stainless steel and non-ferrous aluminum ASME Code equivalent supports and components. Note 3 to LRA Table 3.5.2.26, which applies to all of the cited row numbers, states that there are no applicable aging effects for the material/environment combinations and that this is consistent with industry guidance. The applicant does not credit ASME Code AMP for license renewal.

It was the staff's understanding that the support components covered by the cited row numbers are required to be inspected under IWF during the current licensing term. Therefore, the staff requested that the applicant explain why this CLB commitment would not continue for the extended period of operation.

By letter dated October 8, 2004, the applicant submitted its formal response to the staff, stating that these ASME-equivalent supports and components will continue to be inspected consistent with the commitments contained in the CLB for the ASME Code Section XI Subsection IWF Program requirements in effect during the extended period of operation. The applicant further stated that the specific reference to row numbers noted in the audit team's question all had material and environmental combinations that, upon performance of the AMR, determined that there were no aging effects that required managing for license renewal.

The staff noted inconsistencies between the applicant's AMR for the cited row numbers, all of which are not susceptible to general corrosion, and the applicant's AMR for carbon steel ASME Code equivalent supports and components, which are susceptible to general corrosion. For the cited row numbers, the applicant considers corrosion to be the only age-related mechanism leading to loss of mechanical function. The applicant's position is that the other GALL Report listed mechanisms leading to loss of mechanical function (distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads; elastomer hardening) are not age-related. On this basis, the applicant has concluded that aging management for loss of mechanical function is not applicable to the cited row numbers. However, for carbon steel ASME Code equivalent supports and components, the applicant identified additional GALL Report listed mechanisms as leading to loss of mechanical function (see LRA Table 3.5.2.26, rows 2, 4, 12, and 13); and credits IWF as the AMP for license renewal.

The staff's review of LRA Table 3.5.2.26 identified areas in which additional information was necessary to complete the review of the applicant's results. The applicant responded to the staff's RAI as discussed below.

In RAI 7.2.5-2, dated March 8, 2005, the staff requested the applicant to: (1) submit a detailed description of all supports covered by LRA Table 3.5.2.26, rows 5, 6, 10, 14, 15, 16, and 18; and (2) for each support, provide the technical basis for concluding that every GALL Report listed mechanism (corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads; elastomer hardening) leading to loss of mechanical function is not applicable. As an alternative, the applicant may credit IWF as an AMP for license renewal.

In its response, by letter dated April 5, 2005, the applicant provided its formal response, which states:

> For row numbers 5, 6, 15, and 16 of Table 3.5.2.26, the table will be revised to credit IWF as the aging management program.
>
> The supports for row number 10 are the typical pipe supports comprised of steel structural shapes, welded or bolted together and attached to the concrete structure/building with base plates or attached to other steel structural shapes of the building. The aging effect for GALL III.B1.2.1-a is "Loss of Material" and not "Loss of Mechanical Function" as noted in the question. The AMR is consistent with the reference to Note 3 of Table 3.5.2.26. Additionally, this is consistent with the proposed revision to GALL for Item number III.B1.2-5 (TP-5) for this material and environment combination. The AMR conclusion for the proposed GALL revision to GALL for Item number III.B1.2-5 (TP-5) is "no aging effects are applicable"; therefore, no AMP is required.
>
> The supports in-scope for row number 14 of Table 3.5.2.26 are integral welded lugs to the process pipe. The lug material is the same as the process pipe (aluminum). Aluminum external surfaces are not susceptible to corrosion unless their surfaces are wetted or exposed to an aggressive environment. Since periodic wetting or exposure to aggressive environments of component external surfaces in an inside air environment will not occur, loss of mechanical function due to corrosion is not considered plausible and the other aging mechanisms (distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads; elastomer hardening) do not apply.
>
> The supports in-scope for row number 18 of Table 3.5.2.26 are integral welded lugs to the process pipe. The lug material is the same as the process pipe (stainless steel). The in-scope piping system is located in the Residual Heat Removal Service Water (RHRSW) Tunnels (LRA Section 2.4.3.5). Since the piping and supports are located within the RHRSW Tunnels and are exposed to an inside air environment and are not exposed to an outside air environment as noted in the AMR table, Row 18 can be deleted. Row number 10 (applicable GALL item - III.B1.2.1-a) is the applicable AMR line item for the material and environment combinations of these stainless steel supports in the RHRSW Tunnel.

The staff reviewed the applicant's response and found it acceptable since the AMRs are consistent with the GALL Report. Therefore, the staff's concern described in RAI 7.2.5-2 is resolved.

In RAI 3.5-12, dated December 10, 2004, the staff stated that non-ferrous aluminum conduit and supports that are exposed to outside air are listed in LRA Table 3.5.2.26 as components having no applicable AERM; thus, no AMP is designated to manage their aging. Depending on the severity of the outside air environment to which the components are consistently exposed, some aluminum conduit and supports may experience loss of material aging effect. Therefore, the staff requested that the applicant discuss its past plant-specific inspection results of these supports in order to provide an operating experience-based justification for the above AMR finding.

In its response, by letter dated January 31, 2005, the applicant stated:

> *The following list identifies aluminum components in an outside air environment:*
>
> - electrical and I&C penetrations
> - conduits and supports
> - non-ASME equivalent supports
>
> Aluminum alloys containing zinc are susceptible to corrosion in wetted aggressive environments. However, the outside air environment does not contain contaminants that would cause an aggressive environment. In addition, the aluminum conduit and conduit supports are also constructed of 6063-T42 alloy that is resistant to pitting, crevice corrosion, and SCC (Metals Handbook, Ninth Edition, Volume 13, "Corrosion," ASM International, 1987). Since the potential for concentration of contaminates is not significant, and the specific aluminum grade used in an outside air environment is more resistant to corrosion, loss of function due to corrosion is not considered plausible.
>
> A review of BFN operating history, the structures monitoring baseline inspection, and the results for the first structures monitoring inspection period did not reveal any loss of intended function due to aging effects for the following aluminum components:
>
> - electrical and I&C penetrations,
> - conduits and supports
> - non-ASME equivalent supports

Based on the applicant's additional information provided above and operating experience that (1) the potential for concentration of contaminates at BFN site is not significant, and the specific aluminum grade used in an outside air environment is more resistant to corrosion, loss of function due to corrosion is not considered plausible, and (2) a review of operating history, the structures monitoring baseline inspection, and the results of the first structures monitoring inspection period did not reveal any loss of intended function due to aging effects for the aluminum components. The staff found the AMR results for its aluminum components adequate and acceptable. Therefore, the staff's concern described in RAI 3.5-12 is resolved.

In RAI 3.5-13, dated December 10, 2005, the staff stated that LRA Table 3.5.2.26 lists equipment supports and foundations made of non-ferrous lubrite that are exposed to inside air environment as components having no AERM; therefore, no AMP is designated for the components. NUREG-1801, Table III.B1.1.3-a identifies loss of mechanical function, corrosion, distortion, dirt, overload, fatigue due to vibratory and cyclic thermal loads, and elastomer hardening as potentially applicable aging effects for the lubrite components, and designates ASME Code Section XI, Subsection IWF Program as the AMP to manage the listed aging effects. Therefore, the staff requested the applicant to discuss past plant-specific inspection and maintenance results of these lubrite supports in order to provide an operating experience-based justification for the LRA assessment.

In its response, by letter dated January 31, 2005, the applicant stated:

> The Table 3.5.2.26 entry applies to the lubrite plates used for the Core Spray and RHR pump equipment support plates. EPRI report 1002950, "Aging Effects for Structures and Structural Components (Structural Tools) Revision 1," states that lubrite material 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. lubrite products are solid, permanent, completely self lubricating, and require no maintenance. The Browns Ferry reactor building environment at the location of the Core Spray and RHR pump equipment support plates is not an aggressive or wetted environment.
>
> A search of Browns Ferry and industry operating experience did not identify any instances of Lubrite plate degradation or failure to perform its intended function due to aging effects. NUREG-1759, "Safety Evaluation Report Related to the License Renewal of Turkey Point Nuclear Plant, Units 3 and 4" and NUREG-1769, "Safety Evaluation Report Related to the License Renewal of Peach Bottom Atomic Power Station, Units 2 and 3," concur that there are no aging effects for lubrite plate that require aging management.

Based on the applicant's additional information provided above that (1) the reactor building environment at the location of the core spray and RHR pump equipment support plates is not an aggressive or wetted environment, (2) lubrite products are solid, permanent, completely self lubricating, and require no maintenance, (3) a search of BFN and industry operating experience did not identify any instances of lubrite plate degradation or failure to perform its intended function due to aging effects, and (4) prior staff positions taken with respect to the aging management of lubrite plate under similar environmental conditions, as reported in NUREGs 1759 and 1769, the staff found the applicant's response to RAI 3.5-13 acceptable. Therefore the staff's concern described in RAI 3.5-13 is resolved.

Conclusion. On the basis of its review, the staff found that the applicant appropriately evaluated AMR results involving MEAP combinations that are not evaluated in the GALL Report. The staff found that the applicant demonstrated that the effects of aging will be adequately managed 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).

Sections 3.5.2.3.27 and 3.5.2.3.28. The following AMRs were added as a result of SER Sections 2.4.3.9 and 2.4.7.7, respectively.

3.5.2.3.27 South Access Retaining Walls – Summary of Aging Management Evaluation – Table 3.5.2.27

The staff reviewed added LRA Table 3.5.2.27, which summarizes the results of AMR evaluations for the south access retaining walls component groups.

On the basis of its review of the information provided in added LRA Section 3.5.2.1.27 and Table 3.5.2.27, the staff determined that the applicant had adequately identified applicable aging effects, and the AMP credited for managing the aging effects, for the south access retaining walls components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the south access retaining walls components acceptable.

3.5.2.3.28 Isolation Valve Pit – Summary of Aging Management Evaluation – Table 3.5.2.28

The staff reviewed added LRA Table 3.5.2.28, which summarizes the results of AMR evaluations for the isolation valve pit component groups.

On the basis of its review of the information provided in added LRA Section 3.5.2.1.28 and Table 3.5.2.28, the staff determined that the applicant had adequately identified applicable aging effects, and the AMP credited for managing the aging effects, for the isolation valve pit components that are not addressed by the GALL Report. The staff found the applicant's AMR results for the isolation valve pit components acceptable.

3.5.3 Conclusion

The staff concluded that the applicant provided sufficient information to demonstrate that the effects of aging of the containments, structures, and component supports components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) 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 reviewed the applicable UFSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the containments, structures, and component supports, as required by 10 CFR 54.21(d).

3.6 Aging Management of Electrical and Instrumentation and Controls

This section of the SER documents the staff's review of the applicant's AMR results for the electrical and I&C components and component groups.

3.6.1 Summary of Technical Information in the Application

In LRA Section 3.6, the applicant provided AMR results for components. In LRA Table 3.6.1, "Summary of Aging Management Evaluations for Electrical and Instrumentation and Control Systems Evaluated in Chapter VI of NUREG-1801," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the electrical and I&C components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of AERMs. These reviews included evaluation of plant-specific and industry operating experience. The plant-specific evaluation included reviews of condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine if the applicant had provided sufficient information to demonstrate that the effects of aging for the electrical and instrumentation and control components that are within the scope of license renewal and subject to an AMR will be adequately managed 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 performed an onsite audit during the weeks of June 21 and July 26, 2004, of AMRs to confirm the applicant's claim that certain identified AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in the BFN audit and review report and are summarized in SER Section 3.6.2.1.

In the onsite audit, the staff also reviewed those selected AMRs that were consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the acceptance criteria in SRP-LR Section 3.6.2.2, dated July 2001. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.6.2.2.

In the onsite audit, the staff also conducted a technical review of the remaining AMRs that were not consistent with, or not addressed in, the GALL Report. The audit and technical review included evaluating whether all plausible aging effects were identified and evaluating whether the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the BFN audit and review report and are summarized in SER Section 3.6.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.6.2.3.

Finally, the staff reviewed the AMP summary descriptions in the UFSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the electrical and I&C components.

Table 3.6-1, below, provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.6 that are addressed in the GALL Report.

Table 3.6-1 Staff Evaluation for Electrical and Instrumentation and Controls in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 environmental qualification (EQ) requirements [Item Number 3.6.1.1 (F.4)]	Degradation due to various aging mechanisms	Environmental Qualification of Electrical Components Program	TLAA	This TLAA is evaluated in Section 4.4, Environmental Qualification
Electrical cables and connections not subject to 10 CFR 50.49 EQ requirements (Item Number 3.6.1.2)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure caused by thermal/ thermoxidative degradation of organics; radiolysis and photolysis [ultra violet (UV) sensitive materials only] of organics; radiation-induced oxidation; moisture intrusion	Aging Management Program for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	Aging Management Program for Electrical Cables and Connections Not Subject to 10 CFR 50.49 EQ Requirements	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Electrical cables used in instrumentation circuits not subject to 10 CFR 50.49 EQ requirements that are sensitive to reduction in conductor insulation resistance (Item Number 3.6.1.3)	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced IR; electrical failure caused by thermal/ thermoxidative degradation of organics; radiation-induced oxidation; moisture intrusion	Aging Management Program for Electrical Cables Used in Instrumentation Circuits not Subject to 10 CFR 50.49 EQ Requirements	Aging Management Program for Electrical Cables Used in Instrumentation Circuits not Subject to 10 CFR 50.49 EQ Requirements	Consistent with GALL, with exceptions, which recommends no further evaluation (See Section 3.6.2.1)
Inaccessible medium-votlage (2kV to 15kV) cables (e.g., installed in conduit or direct buried) not subject to 10 CFR 50.49 EQ requirements	Formation of water trees; localized damage leading to electrical failure (breakdown of insulation) caused by moisture intrusion and water trees	Aging Management Program for Inaccessible Medium voltage Cables not Subject to 10 CFR 50.49 EQ Requirements	Aging Management Program for Inaccessible Medium voltage Cables not Subject to 10 CFR 50.49 EQ Requirements	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)

The staff's review of the BFN component groups followed one of several approaches. One approach, documented in SER Section 3.6.2.1, involves the staff's review of the AMR results in the electrical and I&C components that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.6.2.2, involves the staff's review of the AMR results for components in the electrical and I&C systems that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.6.2.3, involves the staff's review of the AMR results in the electrical and I&C components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the electrical and I&C components is documented in SER Section 3.0.3.

3.6.2.1 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Not Recommended

Summary of Technical Information in the Application. In LRA Section 3.6.2.1, the applicant identified the materials, environments, and AERMs. The applicant identified the following programs that manage the aging effects related to the electrical and I&C components:

- Accessible Non-EQ Cables and Connections Inspection Program
- Bus Inspection Program
- Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program

- EQ Program
- Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 EQ Requirements Program

Staff Evaluation. In LRA Table 3.6.2.1, the applicant provided a summary of AMRs for the electrical and I&C components, and identified which AMRs it considered to be consistent with the GALL Report.

For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report does not recommend further evaluation, the staff performed an audit and review to determine whether the plant-specific components contained in these GALL Report component groups were bounded by the GALL Report evaluation.

The applicant provided a note for each AMR line item. The notes described how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with Notes A through E, which indicated that the AMR was consistent with the GALL Report.

Note A indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report and the validity of the AMR for the site-specific conditions.

Note B indicated that the AMR line item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified that the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note C indicated that the component for the AMR line item is different from but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the AMP identified by the GALL Report. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report. However, the applicant identified a different component in the GALL Report that had the same material, environment, aging effect, and AMP as the component that was under review. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the AMR line item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicated that the component for the AMR line item is different from but consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the AMP identified in the GALL Report. The staff audited these line items to verify consistency with the GALL Report. The staff verified whether the AMR line item of the different component is applicable to the component under review. The staff verified whether the identified exceptions to the GALL AMPs had been reviewed and accepted by the staff. The staff also determined whether the AMP identified by the applicant was consistent with the AMP identified in the GALL Report and whether the AMR was valid for the site-specific conditions.

Note E indicated that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different AMP is credited. The staff audited these line items to verify consistency with the GALL Report. The staff also determined whether the identified AMP would manage the aging effect consistent with the AMP identified by the GALL Report and whether the AMR is valid for the site-specific conditions.

The staff conducted an audit and review of the information provided in the LRA and program bases documents, which are available at the applicant's engineering office. On the basis of its audit and review, the staff found that the AMR results that the applicant claims to be consistent with the GALL Report are consistent with the AMRs in the GALL Report. Therefore, the staff found that the applicable aging effects were identified and are appropriate for the combination of materials and environments listed.

Conclusion. The staff evaluated the applicant's claim of consistency with the GALL Report. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing associated aging effects. On the basis of its review, the staff concluded that the AMR results that the applicant claimed to be consistent with the GALL Report are consistent with the AMRs in the GALL Report. Therefore, the staff concluded that the applicant had demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2 AMR Results That Are Consistent with the GALL Report, for Which Further Evaluation is Recommended

Summary of Technical Information in the Application. In LRA Section 3.6.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for the electrical components. The applicant provided information concerning how it will manage the following aging effects:

- electrical equipment subject to EQ requirements
- QA for aging management of NSR components

Staff Evaluation. For component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.6.2.2. Details of the staff's audit are documented in the staff's BFN audit and review report. The staff's evaluation of the aging effects is discussed in the following sections.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification Requirements

EQ is a TLAA requiring further evaluation. TLAAs are evaluated in SER Section 4.

3.6.2.2.2 Quality Assurance for Aging Management of Non-Safety-Related Components

SER Section 3.0.4 provides the staff's evaluation of the applicant's quality assurance program.

Conclusion. On the basis of its review, for component groups evaluated in the GALL Report for which the applicant claimed consistency with the GALL Report, and for which the GALL Report recommends further evaluation, the staff determined that: (1) those attributes or features for which the applicant claimed consistency with the GALL Report were indeed consistent, and (2) the applicant had adequately addressed the issues that were further evaluated. The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.6.2.3 *AMR Results That Are Not Consistent with or Not Addressed in the GALL Report*

Summary of Technical Information in the Application. In LRA Table 3.6.1, the staff reviewed additional details of the results of the AMRs for MEAP combinations that are not consistent with the GALL Report, or that are not addressed in the GALL Report.

In LRA Table 3.6.1, the applicant indicated, via Notes F through J, that neither the identified component nor the material and environment combination is evaluated in the GALL Report and provided information concerning how the aging effect will be managed.

Staff Evaluation. For component type, material, and environment combinations that are not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation.

The applicant's AMR results that are not consistent with the GALL Report, or not addressed in the GALL Report, were not reviewed during the onsite audit.

3.6.2.3.1 Aging Management Evaluations - Fuse Holder

Fuse holders (including fuse clips and fuse blocks) are included consistent with Interim Staff Guidance (ISG)-5, "Identification and Treatment of Electrical Fuse Holders for License Renewal," dated March 10, 2003. ISG-05 added NRC guidance for the identification and treatment of electrical fuse holders for license renewal, which stipulates that fuse holders will be scoped, screened, and included in the AMR in the same manner as terminal blocks and other types of electrical connections. The guidance also says that an appropriate AMP should be adopted to manage the effects of aging where necessary.

Consistent with that staff guidance, the applicant identified oxidation, corrosion of connecting surfaces, moisture or chemical contamination, loosening of connection/thermal cycling, wear, fatigue, loosening of connection/vibration, deformation, and loosening of connection/mechanical stresses as the aging mechanism/effects for the fuse holders.

In the LRA, the applicant stated that plant installation and maintenance practices provide appropriate protection for fuse holders from moisture intrusion, such as in enclosures, since fuse holders are protected by their location within a controlled environment. Therefore, oxidation/corrosion of connecting surfaces due to exposure to moisture or chemical contamination is not an AERM. The applicant also stated that fuse holders in use are designed to withstand the ratings of the fuses they house. Thus, fuse holders are protected from thermal cycling by their design, which prevents the aging effect of fuse clip/finger loosening, and requires no AMP. Fuse holders are mounted in their own support structure separated from sources of vibration; therefore, vibration is not a concern for fuse holders, and an AMP is not required. The fuses are not routinely pulled and reinserted potentially causing fatigue of the fuse holder clips.

Based on the above, the applicant concluded that fuse holders at BFN will maintain their intended function through the period of extended operation with no AMP required.

In RAI 3.6-5, dated November 4, 2004, the staff asked the applicant to justify how a controlled environment could provide protection for fuse holders, preventing aging from the effects of temperature, humidity, radiation, and fatigue. The staff also asked the applicant whether the actual condition of the fuse holders was evaluated to assess the extent of use and whether any visual inspection was performed on the fuse holders; if so, the applicant was requested to provide the findings or explain why an assessment of their current condition was not necessary.

In its response, by letter dated December 9, 2004, the applicant stated:

> A controlled environment, as it pertains to fuse holders, is one where the fuse holder is installed in an enclosure that protects the fuse holder from exposure to moisture and chemical contamination. Enclosures at BFN are designed and selected for the environment in which they are installed. National Electrical Manufacturers Association (NEMA) Standards imposed during the design process ensures the enclosure is suited for the environment in which it is installed. In addition, conduits entering the enclosure were sealed, along with unused knockouts. Enclosure tops and non-welded seams are sealed, along with enclosure and component mounting screws/bolts. Door gaskets supplied with NEMA enclosures are acceptable, or the enclosure door is sealed utilizing engineering approved maintenance instructions.
>
> The aging mechanisms of temperature and radiation are not applicable to the fuse clip portion of fuse holders, but are applicable to the polymeric base material. Polymeric materials of fuse holders utilized at BFN were evaluated as insulated connections and are acceptable for the extended period of operation in the environments in which they are presently installed. None of the polymeric material's 60-year bounding temperature or radiation values were exceeded in any plant space where fuse holders are installed at BFN.

By email dated December 15, 2004, the staff requested additional information on the subject. In its response, by letter dated January 18, 2005, the applicant stated that polymeric materials of fuse holders are included in the Accessible Non-EQ Cable and Connections Inspection Program.

On the issue of fatigue, mechanical stress due to forces associated with electrical faults and transients are mitigated by the fast action of circuit protective devices at high currents. However, mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature. Fuse holders in use are designed to withstand the ratings of the fuses they house and are selected to ensure they are operated below their rated load. Thus by design, fuse holder clips and connections are protected from fatigue failure due to thermal cycling.

Industry operating experience as documented in NUREG-1760 "Aging Assessment of Safety-Related Fuses used in Low- and Medium-Voltage Applications in Nuclear Power Plants," identified that fuse failures due to thermal cycling are attributed to the fuse element, not fuse holder clips. NUREG-1760 documents no instances of fuse holder clip fatigue failures attributed to thermal cycling. A visual inspection performed on a sample located in outdoor weather conditions did not reveal visual signs of corrosion or degradation.

On the basis of its review, the staff found that the applicant had addressed the staff's concern adequately; therefore, the staff's concern described in RAI 3.6-5 is resolved. The staff also found that no AMP is required to manage the aging effects of fuse holders.

3.6.2.3.2 Aging Management Evaluations - Insulated Cables and Connections

In LRA Section 3.6.2.3.2, the applicant identified the electrical failures due to moisture intrusion, which was addressed in SAND 96-0344, "Aging Management Guidelines for Commercial Nuclear Power Plants - Electrical Cable and Terminations," and TR-103834-P1-2, "Effects of Moisture on the Life of Power Plant Cables."

In evaluating these aging effects, the applicant, in the LRA, said that plant installation and maintenance practices provide appropriate protection for connectors from moisture (such as connectors in enclosures or covered with Raychem tubing/splices or tape). Therefore, aging effects related to moisture intrusion for low-voltage cables and connectors do not require aging management for the period of extended operation. However, this aging effect/mechanism is prevalent in medium voltage cables (i.e., water treeing) which is managed by the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

The staff agreed that the applicant had correctly concluded that no separate AMP is required to manage aging effects related to moisture intrusion for low-voltage cables and connectors. The staff found that the GALL Report addressed the aging effect/mechanism in inaccessible medium voltage cables, which will be adequately managed by the applicant's Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program.

3.6.2.3.3 Aging Management Evaluations - High-Voltage Insulators

High-voltage insulators typically used on transmission towers are insulating materials in a form designed to (a) support the conductor physically and (b) separate the conductor electrically from another conductor or object. Materials used for the high-voltage insulators are porcelain and metal.

In LRA Section 3.6.2.3.3, the applicant identified surface contamination, cracking, and loss of material due to mechanical wear as the aging effects/mechanism for high-voltage insulators.

In managing these aging effects, the applicant evaluated these effects as follows:

Surface Contamination - the buildup of surface contamination is gradual and in most areas such contamination is washed away by rain. Contamination buildup on insulators is not a problem due to rainfall periodically washing the insulators.

Cracking - Cracking and breaking of porcelain insulators is typically caused by physical damage, which is not an aging effect and is not subject to an AMR. A review of plant-specific operating experience revealed no instances of insulator cracking or failure related to cement growth at the switchyard. Cracks have also been known to occur with insulators when the cement binds the parts together enough to crack the porcelain. This phenomenon is known as cement growth, and is caused by improper manufacturing process or materials that makes the cement more susceptible to moisture penetration. Therefore, cracking of high-voltage insulators due to cement growth is not an AERM for the period of extended operation

Mechanical Wear - Mechanical wear is an aging mechanism for strain and suspension insulators in that they are subject to movement. Although this mechanism is possible, industry experience has shown that transmission conductors do not normally swing, and when they do swing, as a result of a substantial wind, they do not continue to swing for very long once the wind subsides. In the applicant's evaluation, wear has not been identified during maintenance activities on BFN insulators.

The staff concluded that the applicant had adequately addressed the aging management for high-voltage insulators and agreed that no AMP was required for high-voltage insulators.

3.6.2.3.4 Aging Management Evaluations - Transmission Conductors and Connections

Transmission conductors are uninsulated, stranded electrical cables used in switchyards, switching stations, and transmission lines to connect two or more elements of an electrical power circuit, such as active disconnect switches, power circuit breakers, and transformers, to a passive switchyard bus. Typical transmission conductor materials are aluminum conductor steel reinforced (ACSR).

In LRA Section 3.6.2.3.4, the applicant stated that the portions of transmission conductor within the scope of license renewal for BFN are all aluminum conductors. All aluminum conductors, unlike ACSR, are not as susceptible to environmental influences, such as sulphur dioxide concentration in air. When aluminum corrodes, it forms a protective oxide layer which protects the underlying material from further corrosion. When the steel core of ACSR corrodes due to losing its galvanized coating, it will continually corrode causing a decrease in ultimate strength. The two types of aluminum conductors used at BFN are Orchid, 636 mcm, and Coreopsis, 1590 mcm, which have an ASTM rated strength of 11,000 lbs and 27,000 lbs respectively. The maximum load permitted by TVA design is 3000 lbs for Orchid and 6000 lbs for Coreopsis, which results in a margin of 73 percent and 77 percent of the rated strength. Using the same percent decrease in ultimate strength of 33 percent from the Ontario Hydroelectric test, the aluminum conductors at BFN would undergo a loss of rated strength of 3663 lbs for Orchid and 8910 lbs for Coreopsis. The new rated strength/margin of rated strength would be 7437 lbs/40 percent and 18090 lbs/44 percent for Orchid and Coreopsis, respectively. The ultimate strengths are well above TVA's maximum design load and the National Electrical Safety Code margin of ultimate load, 6660 lbs for Orchid and 16200 lbs for Coreopsis, for the original conductors. Although corrosion of aluminum is minimal, a decrease in ultimate strength due to corrosion similar to that of the ACSR conductor tested by Ontario Hydroelectric shows that the aluminum conductors at BFN will continue to perform their intended functions for the period of extended operation. Further, the applicant stated that transmission and power supply personnel perform normal maintenance activities on all portions of the switchyard, including transmission conductors. These maintenance activities have not revealed any aging effects/mechanisms associated with transmission lines to date. In conclusion, there are no applicable aging effects that could cause loss of the intended function of the transmission conductors. Therefore, loss of conductor strength due to corrosion of transmission conductors is not an AERM for the period of extended operation.

Industry experience has shown that transmission conductors do not normally swing, and that when they do swing in substantial wind, they do not continue to swing for very long once the wind subsides. Therefore, loss of material (wear) and fatigue due to wind loading vibration or sway of transmission conductors are not applicable AERMs for the period of extended operation.

The applicant concluded that no AMP is required.

In RAI 3.6-8, dated November 4, 2004, the staff raised a concern regarding the torque relaxation for bolted connections for transmission conductor and switchyard bus connections.

In its response, by letter dated December 9, 2004, the applicant stated that bolted switchyard bus and transmission conductor connections at BFN utilize Belleville washers, which have torque applied until the Belleville washer is flat, not to exceed limits specified by bolt size. In accordance with industry guidance EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," (Section 7.2.2), increased temperature difference in electrical bolted joints is due to high short circuit ratings or increased current duration. The temperature of an electrical bolted joint will rise and the stress will increase with increasing current duration. If this temperature increase is not taken into consideration, loose, failure-prone joints will result. Belleville washers selected to be flat or almost flat at the installation torque will be used to accommodate the temperature increase. At BFN, connections are routinely surveyed using infrared scan for hot spots, which are indicative of a degraded connection. If a hot spot at a connection is discovered, corrective actions are taken to repair the connection.

In a supplemental letter, dated January 18, 2005, in response to a staff follow-up question, the applicant stated that the infrared scans are performed using Transmission Power Supply Routine Test Schedule. This schedule requires that 500 kV and 161 kV switchyard connections be surveyed after a modification and routinely surveyed every six months. A review of plant-specific operating experience did not reveal any age-related issues associated with bolted switchyard bus or transmission conductor connections; therefore, torque relaxation of bolted switchyard bus and transmission conductor connections is not a concern for BFN.

On the basis of its review, the staff's concern described in RAI 3.6-8 is resolved.

The staff concluded that although corrosion of aluminum is minimal, a decrease in ultimate strength due to corrosion similar to that of the ACSR conductor tested by Ontario Hydroelectric shows that the all aluminum conductors at BFN will continue to perform their intended functions for the period of extended operation. Also, based on the response to the staff concern regarding the torque relaxation for bolted connections, the concern raised in RAI 3.6-8 was resolved. The staff agreed with the applicant's evaluations and concluded that the applicant had adequately addressed the aging management for transmission conductors and connections. The staff also agreed that no AMP was required.

3.6.2.3.5 Aging Management Evaluations - Switchyard Bus

Switchyard buses electrically connect specified sections of an electrical circuit to deliver voltage or current to various equipment and components throughout the plant. The switchyard bus is used in switchyards to connect two or more elements of an electrical power circuit such as active disconnect switches and passive transmission conductors.

In LRA Section 3.6.2.3.5, the applicant identified cracking due to vibration and change in material properties leading to increased resistance and heating as a result of connection surface oxidation as potential aging effects for the high-voltage switchyard bus. In managing the aging effects, the applicant stated that switchyard buses connected to circuit breakers via flexible aluminum conductors, those supported by insulators and by structural supports such as concrete footing or steel structures, do not vibrate. Also, the design process for switchyard bus was engineered to dampen any vibrations that might be induced into the buses. Therefore, cracking due to vibration is not an applicable aging effect for switchyard buses, and an AMP is not required.

The applicant also identified aging effects due to change in material properties leading to increased resistance and heating as a result of connection surface oxidation in aluminum buses. Solid and flexible connectors and ground straps are highly conductive but do not make a good contact surface since pure aluminum exposed to air forms aluminum oxide on the surface, which is nonconductive. To prevent the formation of aluminum oxide on bolted connection surfaces, the connections have a silver plating and are covered with grease to prevent air from contacting the connection surface. The grease is a consumable item that is applied to the connection surface each time a bolted connection is made, thereby precluding oxidation of the connection surface and maintaining good conductivity at the bus connections. Therefore, change in material properties leading to increased resistance and heating as a result of connection surface oxidation of aluminum buses is not an AERM for the period of extended operation.

In RAI 3.6-7, dated November 4, 2004, the staff requested the applicant to provide a discussion of the grease replacement program including the frequency.

In its response, by letter December 9, 2004, the applicant stated that grease is a consumable item that is applied each time a bolted connection is made, and that it precludes oxidation of the connection surface and maintains good conductivity at the bus connections. Connections are routinely surveyed using infrared scan for hot spots, which are indicative of a degraded connection. In its response, the applicant stated that if a hot spot at a connection is discovered, corrective actions are taken to repair the connection. In a supplemental response, dated January 18, 2005, to a staff follow up-question, the applicant stated that the infrared scans are performed using the Transmission Power Supply Routine Test Schedule. The Transmission Power Supply Routine Test Schedule states that 500 kV and 161 kV switchyard connections are surveyed after a modification and routinely surveyed every six months. On the basis of its review, the staff found that its concern described in RAI 3.6-7 is resolved.

The staff concurred with the applicant's evaluation and concluded that no AMP is required to manage these components. The staff also found that the applicant had adequately addressed why these aging effects are not applicable aging effects at BFN. The staff agrees that there is reasonable assurance that the switchyard bus will perform its intended function for the period of extended operation.

Conclusion. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving MEAP combinations that are not evaluated in the GALL Report. The staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

3.6.3 Conclusion

The staff concluded that the applicant had provided sufficient information to demonstrate that the effects of aging of the electrical and I&C components that are within the scope of license renewal and subject to an AMR will be adequately managed so that the intended function(s) 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 reviewed the applicable UFSAR supplement program summaries and concludes that they adequately describe the AMPs credited for managing aging of the electrical and I&C components, as required by 10 CFR 54.21(d).

3.7 Aging Management Review of Unit 1 Systems in Layup for Extended Outage

3.7.1 General Technical Concerns

LRA Section 3.0.1 contains a summary of the evaluation of systems and components subjected to the Unit 1 layup and preservation program. Staff initially reviewed LRA Section 3.0.1 and determined that additional information was required. By letter dated February 19, 2004, the applicant submitted a supplement to the LRA dedicated to the Unit 1 systems in layup during the extended outage. The staff then issued a series of RAIs to obtain additional information on the aging management of components subjected to layup conditions during the extended outage. During the staff review, it was determined that license renewal and plant restart were to be decoupled and, as a result, plant changes to support restart were to be primarily evaluated independently as part of the restart effort. The staff focused its layup and preservation program review on consistency with industry guidance, operating experience including restart inspections, potential latent aging effects, and the adequacy of one-time inspections to manage systems not in service during the extended outage.

In addition to the layup and preservation program, a combination of factors related to operating experience contribute to the way aging effects are managed for systems that were not in service during the extended outage. Those factors are addressed below.

- Length of Extended Outage - The Unit 1 extended outage lasted for approximately twenty years. The length of this extended outage was significantly longer than the extended outage for either Unit 2 or Unit 3 and is unique in the industry. The extended outage limited the amount of Unit 1 operating experience available for review and created abnormal internal environments that contributed to aging.
- Limited Operating Experience - The length of the Unit 1 extended outage limited the amount of operating experience and data available for use in aging management reviews. Unless there is sufficient data available, one-time inspections may not be appropriate to manage systems that were not in service during the extended outage. In response to Item 5.B, discussed below, the applicant provided additional information concerning Units 2 and 3 restart programs and layup operating experience that is applicable to Unit 1.
- Replacement of Components - LRA Appendix F identified that large portions of systems and components were replaced. The basis for material replacement was either the result of excessive degradation caused by ineffective layup practices or potential susceptibility to known degradation mechanisms. The primary concern for aging management is associated with components that were not replaced.
- Suspension of Maintenance Rule - By letter dated August 9, 1999, the staff issued a temporary partial exemption from 10 CFR 50.65 for Unit 1. This partial exemption provided relief from the Maintenance Rule for systems that were not in service to support Units 2 and 3.

Evaluation Findings

SER Section 3.7 contains the staff evaluation of Unit 1 systems subject to layup conditions during the extended outage. SER Section 3.7 includes an evaluation of general technical concerns and system-specific concerns relevant to systems and components subjected to layup conditions. This evaluation determined that, due to a number of factors including (1) service conditions resulting from potentially ineffective layup practices, (2) the length of the extended outage period, (3) limited operating experience, (4) replacement of degraded material due to ineffective layup practices, and (5) suspension of maintenance activities for systems subject to layup, periodic inspections would be more appropriate than one-time inspections to manage aging effects in systems that were subject to layup conditions, where latent aging effects may have existed. The applicant agreed to a periodic inspection program to manage systems that were not replaced and were not in service during the extended outage. Details of the program were not available at the time the SER with open items was prepared. The ACRS interim report dated October 19, 2005, agreed with staff that additional information was required to support the staff review of the wet layup sections and periodic inspection program versus one-time inspection program.

Unresolved Items

By letter dated October 31, 2005, the staff summarized the following unresolved items related to the layup and preservation program and requested the applicant to provide additional information to address unresolved items raised in the committee's interim report:

- Providing suitable input for the wet layup sections for the SER so that the staff can write a cohesive safety evaluation on the applicability of Units 2 and 3 experience to Unit 1.
- Clarification of One-Time Inspection Program versus Unit 1 Periodic Inspection Program and One-Time Inspection Program consistency with the GALL Report.

The applicant, by letter dated November 16, 2005, submitted additional information, discussed below, to close out the unresolved items related to systems subject to the layup and preservation program.

Restart Programs and Unit 2 and 3 Layup Operating Experience Applicable to Unit 1

BFN Unit 1 was licensed and began initial operation in 1973. Unit 2 began operation in 1974. Units 1 and 2 operated until March 22, 1975, at which time both units were shut down due to a fire in the Unit 1 reactor building. Units 1 and 2 resumed operation in 1976 and Unit 3 began initial operation in 1977. All three units were operated until March 1985, at which time the applicant voluntarily shut them down to address regulatory and management issues.

Following successful resolution of the management issues and the Unit 2 and common regulatory issues, Unit 2 was restarted on May 23, 1991. Unit 3 remained in a layup/recovery mode for approximately 10 years and, following resolution of the Unit 3 regulatory issues, it was restarted on November 19, 1995. Both units have operated with high capacity factors into the present time. In the early 1990s, the applicant decided to defer restart of BFN Unit 1.

On May 16, 2002, the applicant announced the Unit 1 restart project. As part of the Unit 1 restart project, the applicant is performing the same restart programs and implementing the same modifications that were previously completed on Units 2 and 3. At restart, Unit 1 will be operationally the same as Units 2 and 3. The current planned Unit 1 restart date is May 2007.

The Unit 1 systems that perform a required function in the defueled condition, or that directly support Unit 2 or Unit 3 operation, have been continuously operated and maintained under applicable technical specifications and plant programs since shutdown in 1985. Examples of these systems are:

- fuel pool cooling system
- portions of the control rod drive (CRD) system
- portions of the raw cooling water (RCW) system
- portions of the reactor building closed cooling water (RBCCW) system
- portions of the residual heat removal (RHR) system
- portions of the residual heat removal service water (RHRSW) system
- portions of the emergency equipment cooling water (EECW) system
- portions of the control air system

The applicant maintained the Unit 1 systems in a physical condition during shutdown similar to that of Units 2 and 3 during their shutdown periods. The internal operating conditions (e.g., water chemistry, flow rate, temperature, etc.) for these systems are the same as those found in the operating units. These systems have experienced the same aging mechanisms and rates experienced by similar Units 2 and 3 systems for shutdown conditions. The Units 1, 2, and 3 reactor buildings are one continuous structure, and the external operating environments of the systems are the same. Even though Unit 1 was in an extended outage, the overall environmental conditions affecting external surfaces in Unit 1 was maintained consistent with those of Units 2 and 3. Unit 1 had the normal ventilation systems in service and equipment was maintained to prevent system leakage so that the equipment was not subjected to aggressive external conditions.

Unit 3 was shut down for approximately 10 years: from 1985 to 1995. The aging effects on Unit 3 were monitored and addressed prior to startup in 1995. Since 1995, Unit 3 has operated with a high capacity factor and was uprated 5 percent reactor thermal power in 1998. During this 10-year period of operation, no additional aging effects have been identified attributable to the 10 years of shutdown and layup. Since Unit 1 was laid up and maintained using the same method as Unit 3, the aging effects during the layup and subsequent operation of Unit 3 would be expected to apply equally to Unit 1. Unit 2 and 3 operations, including power up-rate, have not resulted in any unexpected aging mechanisms or rates. Unit 1 operation, following the shutdown and associated replacements/refurbishments, is expected to exhibit the same aging mechanisms and rates as Units 2 and 3.

Other Unit 1 systems have been in a layup condition, and prior layup experience from Unit 3 has been applied to Unit 1 license renewal. Some piping systems (or portions of piping systems) were placed in a "wet layup" under the applicant's Unit 1 layup procedure, including:

- reactor vessel
- reactor water recirculation system
- reactor water cleanup system

- portions of the RHR system
- portions of the core spray (CS) system
- portions of the feedwater (FW) system

The water chemistry within these Unit 1 piping systems was monitored for compliance with the water quality requirements. Thus, it would not be expected that a different aging mechanism or rate would exist in wet layup compared to what would have occurred if the system were in normal operation. The full scope of BWRVIP inspections have been performed on the Unit 1 reactor vessel as part of the restart project. No adverse effects from the layup period were found and repairs/replacements not related to layup will be performed as required. The reactor water recirculation system and reactor water cleanup system piping, both large bore and small bore, have been replaced. The RHR and CS piping that was in wet layup has also been replaced. The piping was replaced with the same materials that were used in Units 2 and 3. Ultrasonic inspections of the feedwater piping have confirmed that the piping does not exhibit adverse effects from the wet layup period.

Some Unit 1 piping systems (or portions of piping systems) were drained and placed in dry layup, including:

- reactor core isolation cooling (RCIC) system
- high pressure coolant injection (HPCI) system
- main steam (MS) system
- portions of the RHR system
- portions of the CS system
- portions of the FW system

The exterior of the system/component was maintained at nominal reactor or turbine buildings ambient conditions which would have been the same in Units 1, 2, and 3. Thus, the dry layup systems would have experienced aging at a rate less than or equal to that of the corresponding Unit 2 or Unit 3 system.

Some Unit 1 systems were simply drained with no controlled environment. As a result, portions of two Unit 1 systems experienced accelerated aging. The accelerated aging of these systems was previously identified as part of the operating experience from the Unit 3 outage between 1985 and 1995. These were portions of the Unit 1 RHRSW piping inside the reactor building and some small bore raw cooling water piping. As explained below, this prior Unit 2 or Unit 3 operating experience was incorporated into Unit 1 aging management activities.

The RHRSW piping normally contains raw water from the river. Some of the Unit 1 RHRSW piping inside the reactor building was drained in 1985, but moisture-laden air remained in the system. The piping enters/exits from the RHRSW tunnels. Inside the tunnels, the piping is exposed (i.e., not buried) for approximately 100 feet after which it becomes buried pipe out to the intake pumping station. The buried piping could not be drained since it is below grade. Water from the buried section of piping vaporized and entered the drained, above-grade piping in both the tunnels and the reactor building. Inside the RHRSW tunnels, which are approximately 20 feet under an earthen berm, the ambient temperature was cool and no adverse reactions occurred inside the RHRSW piping. However, the RHRSW piping inside the reactor building experienced normal ambient conditions (i.e., 65 °F to 90 °F). In this warm, moisture-laden environment, severe corrosion occurred necessitating complete replacement of the pipe. As shown by ultrasonic measurements of pipe wall thickness and visual observations of pipe interiors, this aging effect was not experienced by buried pipe or above grade pipe that was full of water. This aging effect was restricted to the RHRSW system because it is the only system that was drained but allowed to contain moisture-laden air. This aging was first identified on Unit 3 during the Unit 3 recovery and necessitated the replacement of all of the RHRSW piping inside the Unit 3 reactor building. Based on this lesson learned, the required pipe replacement was performed for the Unit 1 A and C loops of RHRSW piping, which had been in a similar layup fashion to the Unit 3 piping.

The small bore RCW piping was drained; however, due to valve leakage, some water was reintroduced into the system. The combination of water and trapped air set up virtually the same corrosion effects described above for the RHRSW piping. The Unit 1 recovery project has visually and ultrasonically inspected the small bore raw water piping and is replacing approximately 3000 feet of degraded piping.

The Unit 1 restart project did not credit the Unit 1 layup program as the sole means of establishing the acceptability of the associated piping and components for restart. TVA either replaced the piping and components or performed appropriate visual and/or ultrasonic inspections to establish the physical condition of systems and components not being replaced, as discussed in the applicant's letter to the staff, dated May 18, 2005. For systems, piping, and components that were replaced, no layup effects are present. The Unit 1 structures, systems, and components within the scope of license renewal will be subject to the existing BFN aging management programs. As a compensatory measure for systems and components not being replaced, the applicant will perform targeted periodic inspections for the Unit 1 systems that were not replaced as part of the Unit 1 restart project. These inspections will provide heightened assurance that existing AMPs address relevant aging mechanisms and effects for Unit 1.

To ensure there are no latent aging effects as a result of the layup program, BFN will implement a targeted periodic inspection program for Unit 1 system piping that was not replaced as part of the Unit 1 restart project. The restart inspection will provide baseline measurements for targeted inspections to be performed after the unit is returned to operation to verify aging management program effectiveness and to verify the absence of additional latent aging effects. The selected sample will be examined by the same or equivalent methodology as used during Unit 1 restart. Systems (or portions of systems) where periodic inspections will be performed include MS, FW, RHRSW, RCW, EECW, fire protection, reactor building closed cooling water, RCIC, HPCI, RHR, and CRD.

After restart in 2007, Unit 1 would have six years of operation remaining in the current license period, prior to the period of extended operation. The first periodic inspection will be performed during the current license period. An inspection also will be performed during the period of extended operation. Subsequent inspection frequency will be determined based on the inspection results. Inspections will continue until the trend of results provides a basis to discontinue the inspection. There is reasonable confidence that these periodic inspections will be capable of detecting degradation caused by potential latent aging effects after the systems are returned to service.

As part of the AMR in support of the LRA, the applicant recognized that due to the layup period the Unit 1 operating experience may not be the same as the operating experience for Units 2 and 3. Thus, as a further compensatory action, the applicant performed evaluations to identify new aging effects that could be applicable to Unit 1 as a result of the layup environment. The material groupings and aging effects were established using the same approach utilized in the rest of the LRA. A detailed evaluation was performed for 19 Unit 1 systems. It was concluded that there were no new AERMs during the renewal term. A summary of these evaluations is provided in LRA Section 3.0.1. The applicant provided additional details of this evaluation in its letter to the staff dated February 19, 2004.

As part of its review of the applicant's LRA, the staff, by letter dated August 23, 2004, identified areas where additional information was needed to complete its review. The specific staff questions were from LRA Sections 3.1, 3.2, 3.3, and 3.4 and were related to aging of mechanical systems during the extended Unit 1 outage. Listed below are the specific staff requests for additional information, responses to a number of staff follow-ups, and the LRA. There were no additional aging effects because of the extended outage of Unit 1 and, consequently, the applicant claimed that there was no need for any additional aging management. However, in its letter dated August 23, 2004, the staff said that since the aging of mechanical systems is highly dependent on the environment maintained during the extended outage, the staff needed additional information to determine whether:

- Additional or more severe aging occurred during the extended outage.
- Additional aging has been properly identified, evaluated, and managed.
- The proposed aging management can distinguish the aging during the extended outage from the aging during future operation.

By the initial set of RAIs dated August 23, 2004, the staff issued general and system-specific RAIs on the aging of mechanical systems during the extended outage of Unit 1. The applicant responded to the initial RAIs by letter dated October 8, 2004. The staff reviewed the applicant's RAI responses and, by letter dated December 16, 2004, requested additional information in a set of follow-up RAIs. The applicant responded to these RAIs by letters dated January 20, and January 31, 2005. System-specific RAIs are identified by a system-specific LRA prescript and a subscript "LP" to designate a layup RAI. Finally, the applicant resolved all the staff issues regarding the Unit 1 layup by its responses dated May 18, and May 27, 2005. RAIs (3.0-1 LP through 3.0-11 LP) are applicable to all systems. Given below are the safety evaluations of technical areas in which the staff had specific concerns relative to the Unit 1 system in the extended layup and its rationale for acceptance.

3.7.1.1 Wet Layup Program Chemistry Control

In the wet layup for Unit 1, the applicant characterized chemistry for the wet layup water as flowing, air-saturated, and demineralized. Since in the BFN plant only the systems carrying the reactor cooling water are included in the wet layup program, the chemistry of the demineralized water has the same chemistry as the cold shutdown reactor cooling water during normal plant outages.

The initial set of general RAIs that are referenced in the discussion that follows constitutes the staff request dated August 23, 2004. The applicant's responses are in its letter dated October 8, 2004.

In its response to RAI 3.0-1 LP by its letter dated October 8, 2004, the applicant stated that the other plant systems with different plant chemistries were not included in the wet layup program because during the Unit 1 outage they were maintained at the operating conditions, including water chemistries, found in Units 2 and 3 during their normal operations. The cold shutdown chemistry is specified in the BFN CI-13.1 chemistry program. In the response to the staff's question the applicant stated that the chemistry control limits implemented during wet layup are 1.5 µS/cm for water conductivity, and 15 ppb for the concentration of chloride and sulfate. These values are the same as the chemistry control limits utilized in Units 2 and 3 operating in the cold shutdown mode for refueling and maintenance outages. They are more restrictive than those in the EPRI Water Chemistry Guidelines specified in BWRVIP-79 and, therefore, introduce conservatism to the values of the CI-13.1 chemistry program used to specify water chemistry during the wet layup.

Since water conductivity and concentration of chlorides and sulfates are the main parameters characterizing water chemistry, as long as they don't differ, the wet layup and cold shutdown chemistries are comparable. The staff concurred, therefore, with the applicant that the effect of chemistry on the components in wet layup and cold shutdown will be similar, and the exposure of the components to the wet layup chemistries will be similar to the effect of the exposure to reactor water during the cold shutdown mode of operation.

3.7.1.2 Replaced Components

LRA Appendix F indicates that significant sections of piping and components have been or will be replaced prior to Unit 1 restart. It was not clear to the staff whether LRA Appendix F included all piping that had been or would be replaced prior to restart. The applicant's responses to staff RAI for LRA Section B.2.1.4, developed during the license renewal audit inspection during the weeks of June 21 and July 26, 2004, state that repaired or replaced components will receive a preservice examination in accordance with the requirements of IWB, IWC, or IWD of the component being repaired or replaced, and prior to returning the system to service. In this response, the applicant also stated that a re-baseline inspection will be performed on the remaining Class 1, 2, and 3 components that have not been repaired or replaced.

In RAI 3.0-9 LP (refurbished vs left in place), dated December 16, 2004, the applicant was requested to provide information to identify the basis, such as inspections or suspected degradation, to determine which components need to be replaced and those that do not. Also, the applicant was requested to clarify whether Appendix F includes all piping and components that will be replaced prior to startup and to identify in a simplified boundary diagram those specific sections of piping and components that have recently been or will be replaced and those that have not been replaced. Further, the applicant was requested to clarify appropriate layup or cleanliness programs (Refer to RAI 3.0-11 LP) and inspections that are in use and planned for these components. For those systems or portions of systems and components that have not been recently replaced and were subject to the extended layup, the applicant was requested to provide the information requested in RAI 3.0-10 LP (inspection information, concerning inspections).

In its response, by letter dated January 31, 2005, the applicant stated that the overall management philosophy for the Unit 1 restart was to return the plant to operation in a condition that would support long-term safe and reliable operation of the unit, including the

20-year period following license renewal. The applicant further stated that, with this management philosophy as a basis, it had applied lessons learned from the Units 2 and 3 restart programs and operating experience from all three units in its decision to replace large portions of key piping systems. The RAI 3.0-9 LP response also states that the Unit 1 restart project did not credit the layup program as the sole means of establishing the acceptability of the associated piping and components. Rather, the applicant either replaced the piping and components or performed appropriate inspections to establish the physical condition of systems and components not being replaced.

The applicant's response to RAI 3.0-9 LP also states that LRA Appendix F did not include all piping and components that will be replaced prior to startup.

In summary, the RAI response concluded that the application of the targeted sampling inspections and the number of inspections performed has established a high level of confidence that those systems with any question about their integrity have been identified, inspected, and properly addressed relative to the replacement or non-replacement of the piping system and/or its components. The combination of piping replacements identified through previously identified design issues, operating experience, and other inspections identified approximately 16,000 feet of large bore piping and 26,000 feet of small bore piping to be replaced. The applicant further stated that the results of the reviews of operating experience, design issues, and inspections is provided in Table 1 of the RAI response. The systems listed are those in which significant piping or components were identified for replacement or refurbishment. In its response, the applicant presented in Table 2 of the submittal dated January 31, 2005, the details and extent of the RPV vessel inspection project (VIP) inspections and ASME Section XI re-baseline inspections that will be conducted on Unit 1 piping systems prior to operation. Finally the applicant stated that the re-baseline effort is equivalent to performing a complete 10-year interval's quantity of examinations during the Unit 1 restart effort.

The staff reviewed the applicant's response to RAI 3.0-9 LP and found the response to be reasonable and acceptable to clarify the general scope of replaced and refurbished components including the basis for replacing certain components and not others. The applicant's response and the staff's evaluation of the response is included in the applicable section for each system.

The applicant's response to RAI 3.0-9 LP states that LRA Appendix F did not include all piping and components that will be replaced prior to startup. As a result, LRA Appendix F cannot be used as a means to distinguish between sections of piping systems and components that have been replaced and those that have not been replaced. Although the response to RAI 3.0-9 LP identifies examples of piping systems and components that have been replaced, the staff is unable to identify specific components that have not been replaced that were subject to layup conditions. Further, the scope and results of sample inspections, including the sampling basis, have not been identified. To identify the scope and condition of components subject to Section XI or VIP inspections, the applicant was requested to identify the sampling basis and inspection results for piping systems and components subject to layup conditions that have not been replaced. The staff identified this as an unresolved issue (URI). The staff discussed this issue with the applicant in follow-up teleconferences. The following is a disposition of the resolution of the issues in the staff follow-ups, as documented in subsequent applicant submittals.

The applicant's response, by letter dated May 18, 2005, clarified its response to RAI 3.0-9 by stating that a large amount of piping in the drywell and reactor building had been replaced, but the majority of the piping had been inspected and determined to be acceptable without replacement. The applicant submitted a table to identify the UT examinations performed to demonstrate that the existing piping has wall thickness in excess of the manufacturer's minimum nominal wall thickness (>87.5 percent of nominal) and did not require replacement. The non-replaced piping inspected included the RHRSW, fire protection, emergency equipment cooling water (EECW), raw cooling water (RCW), CRD, core spray, feedwater, HPCI, main steam, reactor core isolation cooling (RCIC), RHR, and RBCCW systems. The locations chosen for thickness examinations were susceptible areas that may have contained moisture during layup, or where engineering evaluation determined wear may have occurred. By letter dated May 27, 2005, the applicant submitted an additional clarification that the susceptible locations were those areas determined to have the highest potential for service-induced wear or latent aging effects, which include all types of corrosion. The applicant also clarified that the inspection techniques utilized evaluate internal conditions and are sensitive to the presence of unacceptable conditions including wear, erosion, corrosion, including crevice corrosion if present. By letter dated November 16, 2005, the applicant further clarified that visual and/or ultrasonic inspections establish the physical condition of systems and components not being replaced.

The staff reviewed the applicant's response and found the response acceptable. The applicant clarified that, for piping not replaced that was in a layup condition during the extended outage, UT examinations had been performed at susceptible locations having the highest potential for service-induced wear or latent aging effects to demonstrate that adequate wall thickness exists. There is reasonable assurance that a combination of internal visual inspections and UT inspection techniques applied are adequate to detect wear, erosion, and corrosion, including crevice corrosion. There is also reasonable assurance that the Corrective Action Program will continue to be applied to repair or replace degraded material identified in the inspections prior to adversely affecting the component intended function. Therefore, all issues related to the staff issue on replaced components are resolved.

3.7.1.3 Inspections Verification Programs for Layup and Chemistry Control

The SER with open items (OIs) issued on August 9, 2005, loosely used the terms "One-Time Inspection," "Restart Inspection," and "Periodic Inspection." The ACRS, in its 526th committee meeting and subsequently in its Interim Report dated October 19, 2005, asked the staff to provide clarity on these inspection terms and for the final SER to correctly reflect the intent of the inspections to be performed. Accordingly, the staff sought clarifications on these terms. In its submittal, by letter dated November 16, 2005, the applicant provided the following definitions of the inspection terms and clarified its interpretation of these inspections in previous submittals (RAI 3.0-10 LP, responses to URIs 3.0-2 LP, 3.0-3 LP, and 3.0-4 LP). The staff has since reviewed the SER with OIs and the final SER reflects the use of these definitions as provided below:

> One-Time Inspection - The applicant's One-Time Inspection Program, B.2.1.29, is consistent with GALL AMP XI.M32, "One-Time Inspection." These inspections include measures to verify that unacceptable degradation of any reactor system component is

not occurring, validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation.

Restart Inspection - These inspections are used as a means of verifying the material conditions of the system(s) of interest prior to the Unit 1 restart. These are performed prior to restart. These inspections are implemented to return Unit 1 to operation for the remainder of the current licensed operating period. In its submittal, by letter dated November 16, 2005, the applicant stated that the restart program does not take credit for the layup in returning a system to operations and instead depends on inspections and/or replacement to ensure the components are satisfactory for the remainder of the current licensed operating period.

Unit 1 Periodic Inspections - These inspections are for Unit 1 systems that have been shutdown during the extended layup and that were not subsequently replaced as a part of the Unit 1 restart project. These are targeted periodic inspections that will be performed on chosen systems after Unit 1 is returned to operation. The intent is to verify the effectiveness of AMPs and to verify that no additional latent aging effects are occurring. The staff agreed that the results from the Unit 1 restart inspection can be used as a first set of data points. These inspections are periodic in nature and performed prior to and during the period of extended operation until the applicant determines that no unacceptable degradation is occurring. The applicant's Unit 1 Periodic Inspection Program is described in AMP.B.2.1.42.

Systems Maintained in Dehumidified Air - The staff reviewed information presented in LRA Table 1 supplement dated February 19, 2004, on wet layup and determined that additional information was required. In RAI 3.0-2 LP, dated August 23, 2005, the staff requested the following additional information on Table 1 components in dry layup.

For the systems covered by Table 1, the applicant stated that during layup, the systems were maintained in dehumidified air (60 percent relative humidity) and no additional aging effects were identified for the layup condition.

NRC Inspection Report 50-259/87-45 reported that in 1987 an acceptable program for monitoring the relative humidity of all pipe environments had not been finalized and the extent to which all parts of each system was being continually purged with dry air had not been established. For example, the standby liquid control system contained moisture in portions of the system and procedures did not require the system to be monitored for dryness. Although inadequacies in the program were later resolved, it appears that the moisture concerns existed for an extended period of time.

Also, industry documents such as EPRI NP-5106, "Sourcebook for Plant Lay-up and Equipment Preservation," revision 1, identify the need to monitor the effectiveness of the layup practices. This document states that relative humidity (RH) cannot be used alone as a layup surveillance technique to evaluate layup effectiveness.

Table 1 does not identify any additional inspections prior to Unit 1 restart to assess the condition of these systems, and it is not clear if inspections were performed in the layup condition. In light of the above inspection findings, the recommendations in the industry documents, and the possibility that parts of this system may not have been continually purged with dry air (such that the exact dryness of the surrounding air cannot be ascertained), discuss any inspections planned before startup to address the potential aging during the extended outage, and whether these inspections target system low points where condensate and/or chemicals could accumulate. If inspections have been performed recently, discuss the results of the inspections. If no inspections to verify the aging during the extended outage are planned, provide justification for not performing such inspections. Describe the process that was used to maintain equipment in a dry layup condition. Discuss how humidity was controlled and maintained below 60 percent, whether the 60 percent is relative to the coldest portion of the system, the results of any monitoring and trending of the air quality and humidity, and the corrective actions taken (including any inspections) for any conditions where the humidity criterion was exceeded (including corrective actions for the conditions identified in the above inspection report). Also, Table 1 identifies that future one-time inspections are planned. Discuss how the one-time inspections will differentiate between the rate of aging in the different environments (operation vs. shutdown), and discuss whether the one-time inspections will target locations that are susceptible to aging during normal operation or during shutdown.

In its response, by letter dated October 8, 2004, the applicant stated that, for components within the dry layup systems, a one-time inspection (restart, per letter dated November 16, 2005) will be performed prior to Unit 1 restart to verify the material condition. The applicant further stated that the One-Time Inspection Program does not differentiate between the rate of aging in different environments (i.e., normal power operation versus cold shutdown).

Components in a Lubricating Oil Environment. - In RAI 3.0-4 LP, dated August 23, 2004, the staff requested the following additional information for managing components exposed to a lubricating oil environment.

For components in a lubricating oil environment, the LRA identified no AERMs. The applicant was requested to discuss how the lubricating oil was maintained during the extended outage. The applicant was also requested to discuss whether testing was performed to verify the oil qualities, including moisture, that would affect aging. If the lubricating oil was drained, the applicant was requested to discuss the resulting environment and any applicable aging degradation. The applicant was further requested to discuss any planned inspections to verify that there was no significant aging during the extended outage.

In its response to RAI 3.0-4 LP, dated October 8, 2004, the applicant stated that no maintenance or testing was performed for the recirculation system lubricating oil environment during plant layup. However, this lubricating oil environment is being deleted by design change notice (DCN) 51219A, which replaces the recirculation pump MG sets with a variable frequency drive. This modification has been installed on Units 2 and 3 and will be installed on Unit 1 prior to restart.

The applicant further stated that no maintenance or testing was performed for the reactor core isolation cooling system or the HPCI system lubricating oil environment during plant layup.

However the applicant clarified that a sample of components with a lubrication oil environment within these systems will be inspected for the following aging effects by the One-Time Inspection Program.

- carbon and low-alloy steel – loss of material due to general corrosion, crevice corrosion, pitting corrosion, and galvanic corrosion
- stainless steel - loss of material due to crevice corrosion and pitting corrosion
- copper and copper alloys – loss of material due to crevice corrosion, pitting corrosion, galvanic corrosion, and selective leaching
- cast iron and cast iron alloys - loss of material due to general corrosion, crevice corrosion, pitting corrosion, galvanic corrosion, and selective leaching

Systems Exposed to Air/Gas Environment - In RAI 3.0-5 LP, dated August 23, 2004, the staff requested the additional information for systems exposed to an air/gas environment. Tables 2 and 3 show that some components are exposed to an air/gas internal environment during normal operation, but state that this environment is not applicable during the extended outage. These tables state that, due to drainage and system isolation, portions of several systems may have been exposed to an internal environment of moist air. These tables also state that the evaluation for treated water encompasses the aging effects for a moist air environment in these systems. However, Tables 2 and 3 identify additional aging effects for moist air than they identify for treated water (for example, cracking in low points where condensation and chemicals can accumulate). Clarify the above discrepancy in Tables 2 and 3. Also, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated water environment, explain why the evaluation of the aging effects for the treated water environment would encompass that of the aging effects for a moist air environment in these systems. Tables 2 and 3 state that one-time inspections are planned for the components that are exposed to an air/gas internal environment. The applicant was requested to discuss the plans for additional inspections before startup of Unit 1 to evaluate aging during the extended outage, or inspections that were performed during the extended outage. If no such inspections are planned or none have been performed, provide justification that they are not needed and discuss how the one-time inspection will distinguish between the rate of aging in the different environments.

In its response to RAI 3.0-5 LP, dated October 8, 2004, the applicant stated that Table 2 Systems [RVIs, Feedwater (03), Reactor Vessel Vents and Drains (10), Reactor Recirculation (68), Reactor Water Cleanup (69) and Control Rod Drive (85)] and Table 3 Systems [Condenser Circulating Water (27), Gland Seal Water (37), Containment (64), Reactor Core Isolation Cooling (71), High Pressure Coolant Injection (73), and Core Spray (75)] address the portions of these systems laid up in a wet environment. Due to closure sequence, closure timing, and possible leakage past the double isolation valves or two drain valves for these systems, it is assumed that an air/gas environment with an uncertain amount of moisture was trapped between the double isolation valves. The trapped moisture between the double valves was considered the same, (i.e., treated water or raw water) as water flowing through the valves prior to closure. N/A (not applicable) denotes that this trapped air/gas environment will be evaluated under the corresponding raw or treated water evaluations.

The applicant further stated that during layup the temperature of the systems addressed in Tables 2 and 3 were less than 140 °F. Therefore, crack initiation and growth due to SCC is not a concern for stainless steels and nickel-based alloys in a wet layup environment.

The applicant clarified that the evaluation of these moist air environments for the systems addressed in Tables 2 and 3 identified no additional aging effects other than those identified for the corresponding raw or treated-water environment. The LRA identified these trapped air environments for restart inspection because the extent of corrosion could be quantified. It was not the intent of this AMR to determine the rate of loss of material, but only to verify its material condition. The applicant stated that the inspection will be performed prior to Unit 1 restart.

Systems Not Part of Wet Layup Program - In RAI 3.0-6 LP, dated August 23, 2004, the staff requested the following additional information on systems that were not part of the wet layup program and were exposed to stagnant treated (non-controlled) or raw water.

Table 3 of Evaluation of BFN Unit 1 Lay-up and Preservation Program (submittal dated February 19, 2004) identifies several systems that were not incorporated into the Unit 1 wet layup program. These systems were exposed to treated (non-controlled) or raw water during the extended outage. Table 3 concluded that there is no additional aging management for these systems. The staff required additional information on the following: (1) discussion of the results of any water samples, including pH, oxygen levels, aggressive chemical species, biological activity, and corrosion product levels, (2) discussion whether the systems were stagnant or periodically flowed, (3) discussion whether the plans for prestartup inspections to determine the loss of material due to general, pitting, and crevice corrosion, MIC, dealloying, and galvanic corrosion, or provide justification that such inspections are not needed, and (4) also, discussion of inspections for the degradation of other materials, such as elastomers and other non-metallic materials.

In its response to RAI 3.0-6 LP, dated October 8, 2004, the applicant stated:

> Condenser Circulating Water System (27) - System 27 was exposed to Tennessee River water which is the same environment it is exposed to during normal operation. Without the addition of foreign chemicals the aging effects during normal operation and during layup are the same.
>
> Gland Seal Water System (37) - The system was drained (ambient air present) with the gland seal tank in component layup per MPI-1-000-TNK002. However, it was assumed that the secondary containment loop seal as well as other low points in the system were not completely drained. The applicant stated that therefore, stagnant treated water supplied from the condensate system was evaluated for these areas.
>
> Systems (Containment (64), Reactor Core Isolation Cooling (71), High Pressure Coolant Injection (73), and Core Spray (75) - The torus and torus attached piping for System 64 (i.e., the torus itself) and for Systems 71, 73, and 75 (torus attached piping) saw torus water maintained by Chemistry Program CI-13.1, Appendix A, Table 20) for extended periods of time until the torus was drained in the summer of 2003. When filled, the torus is approximately half full of water with the other half ambient air. The torus water was not "flowing" in that the only significant water movement was relatively infrequent transfers into and out of the Unit 1 torus. The torus on an operating unit cannot be

considered "flowing" either. The operating unit's torus would also be nitrogen-inerted. Torus coating touch-up/repair is part of the restart work to be completed while the torus is drained. The torus impurity administrative goals for conductivity, chloride, and sulfate given in CI-13.1 are 2.0. μS/cm, 75 ppb, and 75 ppb, respectively. The applicant stated that a review of sampling data showed that the torus water was maintained within the chemistry specifications and that sampling is performed quarterly. In respect to these systems, the applicant will perform restart inspection prior to Unit 1 restart to verify the material condition.

Inspections to be Performed Prior to Restart - In RAI 3.0-7 LP, dated August 23, 2004, the staff requested the following additional information on Notes 1 and 2 of Tables 2 and 4 concerning inspections to be performed prior to the Unit 1 restart.

Notes 1 and 2 of Tables 2 and 4 indicate that a restart inspection will be performed prior to Unit 1 restart for certain components where additional aging effects were identified for the extended shutdown. Examples include additional aging effects for copper alloy, cast iron, cast iron alloy, and stainless steel components in system locations where condensation could build up, and carbon and low-alloy steel in an internal environment. No descriptions of the inspections were provided. The staff asked the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections.

The applicant responded to RAI 3.0-7 LP by stating that Note 1 of Tables 2 and 4 identifies the potential for external general corrosion on carbon and low-alloy steel components that are normally operated at temperatures greater than 212°F. This note is applicable to the reactor vessel (RV), feedwater system (03), and the heater vents and drains system (06). External surface monitoring is performed in accordance with the Systems Monitoring Program described in the LRA Section B.2.1.39. The applicant stated that this is the same AMP proposed for managing external loss of material during the period of extended operation.

The applicant also stated that Note 2 of Tables 2 and 4 identifies the potential for internal loss of material and cracking (aluminum only) that are normally exposed to either dry air or nitrogen. The applicant clarified that this note is applicable to the following systems and materials:

Feedwater (03)	Copper Alloy
Main Steam (01)	Aluminum Alloy
Containment Inerting (76)	Carbon and Low-alloy steel Stainless Steel Nickel Alloy Copper Alloy Aluminum Alloy Cast Iron

Containment Atmosphere Dilution (84)	Carbon and Low-alloy steel Stainless Steel Copper Alloy Aluminum Alloy Cast Iron

The applicant's response to RAIs 3.0-2 LP, 3.0-3 LP, and 3.0-4 LP, by letter dated May 27, 2005, clarified that this is a restart inspection.

Management of Galvanic Corrosion - In RAI 3.0-8 LP, dated August 23, 2004, the staff requested the following additional information on management of galvanic corrosion with the water chemistry and one-time inspections.

The LRA and the supplement dated February 19, 2004, are not clear regarding the management of galvanic corrosion. There is the potential for galvanic corrosion during the extended outage for those systems that were maintained in wet layup, wet non-layup, or moist air such that condensation and pooling could occur. The LRA and Reference 2 state that galvanic corrosion is managed through use of the Chemistry Control Program and the One-Time Inspection Program; however, there were differences in water chemistry during the extended outage, and the One-Time Inspection Program does not cover galvanic corrosion. The applicant was requested to describe how galvanic corrosion during the extended outage is managed. The applicant was also requested to discuss any inspections that are planned to determine the extent of galvanic corrosion during the extended outage.

In its response to RAI 3.0-8 LP, dated October 8, 2004, the applicant stated that the Chemistry Control Program implemented during the extended outage is the same program that BFN uses on the two operating units during cold shutdown conditions for refueling and maintenance outages. This extended outage program would consist of CI-13.1 chemistry program controls, which would continue to be based on the EPRI BWR Water Chemistry Guidelines (TR-103515). The applicant further stated that the One-Time Inspection Program utilized to verify the effectiveness of the Chemistry Control Program for preventing loss of material will select the susceptible locations (where materials with different electrochemical potentials are in contact in the presence of contaminants). Finally the applicant stated that galvanic corrosion is included in the One-Time Inspection Program.

In regard to SCC, the staff found the applicant's response to RAI 3.0-5 LP to be reasonable and acceptable, because the applicant clarified that during layup the temperature of the systems addressed in Tables 2 and 3 was less than 140 °F in a wet layup environment; therefore, crack initiation and growth due to SCC is not a concern for stainless steels and nickel-based alloys. In Tables 2 and 3, SCC is correctly identified as an aging effect for stainless steel during plant operation at elevated temperatures and SCC is managed by various AMPs.

The staff reviewed the applicant's responses to the above RAIs and determined that additional information was required concerning the application of the One-Time Inspection Program as a verification program for layup and chemistry controls. By letter dated December 16, 2004, staff submitted RAI 3.0-10 LP requesting the applicant to provide additional information on one-time inspections.

The staff reviewed the applicant's responses to the above RAIs and determined that additional information was required concerning the application of the One-Time Inspection Program as a verification program for layup and chemistry controls.

In RAI 3.0-10 LP, dated December 16, 2004, staff stated that industry guidance on recovering plants placed in extended layups such as Browns Ferry specifically recommends that a surveillance and assessment program is needed to monitor the effects of outage or storage conditions on nuclear power plant components, otherwise, evidence of bad layup often will not even manifest itself until after a plant has returned to power. In pursuing this line of reasoning, the staff requested that the applicant clarify if one-time inspections may not be appropriate where degradation is expected to occur or occur very slowly. Specifically, for systems not associated with the BWRVIP program, the staff wanted the applicant to justify why a one-time inspection is appropriate for aging management in lieu of periodic inspections. By letter dated May 27, 2005, the applicant clarified the application of periodic inspections in lieu of one-time inspections for areas subject to concentration of contaminants during layup. Targeted periodic inspections are going to be used as compensatory actions to be performed after Unit 1 is returned to operation to verify that no additional aging effects are occurring. By letter dated November 16, 2005, the applicant also clarified that the compensatory actions included visual and/or ultrasonic inspections to establish the physical condition of systems and components not being replaced. The first periodic inspection will be performed prior to the end of the current operating period, and the subsequent frequency will be determined based on the outcome of the first periodic inspections performed.

The restart inspections can be utilized as a baseline for comparison as identified in the Unit 1 Periodic Inspection Program (SER Section 3.0.3.3.5). Systems and portions of systems for which periodic inspections will be performed included MS, FW, RHRSW, RCW, EECW, fire protection, reactor building closed cooling water, RCIC, HPCI, RHR, and CRD. The staff concurred that application of targeted periodic internal visual and ultrasonic inspections of a sample of susceptible locations is appropriate to manage potential latent aging effects in Unit 1 systems and portions of systems in layup that were not in operation during the extended outage and have not been replaced.

These staff dialogues and the ACRS interim report, dated October 19, 2005, led to the development of a new plant-specific AMP B.2.1.42, "Unit 1 Periodic Inspection Program," for BFN Unit 1 components that will not be replaced before restart.

3.7.1.4 MIC

In RAI 3.0-3 LP, the staff requested the following additional information on MIC:

> Industry documents such as EPRI NP-5106, indicate that all metals are susceptible to MIC, especially in stagnant and low flow areas, and microbes in the system should be monitored by an adequate program at least every week and more often in outages. NRC Inspection Report 50-259/87-45 identified damage due to MIC had already occurred in the fire protection system and water samples in the demineralized water system were planned. Table 2 does not identify MIC as a corrosion mechanism (for example, in the RWCU and CRD systems for systems intended for wet layup with demineralized water. Table 3 does not identify MIC as a corrosion mechanism for systems that had no water

chemistry control (wet, non-layup) during the extended outage. Similarly, Table 4 does not identify MIC as a corrosion mechanism for components subject to a moist air environment for extended periods of time. Provide technical justification that MIC is not an aging mechanism applicable to the stagnant, low flow, and moist air portions of the mechanical systems. Alternatively, describe how inspections would detect loss of material caused by MIC at susceptible locations.

In its response to RAI 3.0-3 LP, by letter dated October 8, 2004, the applicant stated:

> Table 2 contains Systems [Reactor Vessel and Internals (RVI), Feedwater (03), Reactor Vessel Vents and Drains (10), Reactor Recirculation (68), Reactor Water Cleanup (69) and Control Rod Drive (85)] laid up with demineralized water maintained by the Chemistry Program CI-13.1 and moist air from possible pooling of Chemistry Program CI-13.1 controlled treated water between drain valves and double isolation valves due to closure sequence, closure timing, and possible leaking past the valves. Although portions of these systems had stagnant, low flow, and moist air environments, the Chemistry Program prevented the presence of microbes necessary to cause MIC damage. A review of BFN PERs and Work Orders (WOs) (operating experience) did not identify MIC as a concern in treated water.
>
> Table 3 contains Systems [Condenser Circulating Water (27), Gland Seal Water (37), Containment (64), Reactor Core Isolation Cooling (71), High Pressure Coolant Injection (73), and Core Spray (75)].
>
> 1. MIC is identified as a concern for raw water environments regardless of flow rate in the Condenser Circulating Water System (27).
> 2. The laid up environment for the Gland Seal Water System (37) was treated (condensate) water and moist air from possible pooling of treated water between drain or isolation valves and in the loop seals. BFN operating experience did not identify MIC as a concern in treated water environments. Although there were no chemistry controls placed on system 37 during layup, raw water or other MIC agents were not introduced into this system. Therefore, the microbes necessary for the propagation of MIC were not present in this system during layup.
> 3. Treated (torus) water was maintained by the Chemistry Program CI-13.1 during wet layup. The portions of Systems [Containment (64), Reactor Core Isolation Cooling (71), High Pressure Coolant Injection (73), and Core Spray (75)] within the BFN LR scope (torus and torus attached piping) during Unit 1 layup had a treated water environment and moist air from possible pooling of treated water (torus water) between drain valves and double isolation valves due to closure sequence and timing and possible leaking past the valves. Although portions of these systems had stagnant, low flow, and moist air environments, the Chemistry Program CI-13.1 prevented the presence of microbes necessary to cause MIC damage. A review of BFN PERs and WOs (operating experience) did not identify MIC as a concern in treated water.
>
> Table 4 Systems [Main Steam (01), Condensate (02), Heater Drains and Vents (06), Containment Inerting (76), and Containment Atmosphere Dilution (84)] contained treated water or nitrogen prior to Unit 1 layup. These systems were drained during

layup. These systems were isolated without the introduction of raw water or other MIC agents. Therefore, the microbes necessary for the propagation of MIC were not present in these systems during layup.

In a follow up to the general RAI 3.0-10 LP, dated December 16, 2004, the applicant was requested to clarify why one-time inspections are appropriate for locations with stagnant, low flow or intermittent flow where MIC is expected on the basis of industry operating experience due to possibly ineffective chemistry control in these regions. The applicant was asked to identify the results of any inspections performed in low flow or stagnant areas to demonstrate that aging effects are not expected to occur or are expected to occur slowly. The applicant was also requested to provide information on any corrosion monitoring programs for MIC, including augmented inservice inspection of susceptible areas and corrosion coupons or spool pieces. Otherwise, the applicant should consider the application of periodic inspections to evaluate aging effects in these areas.

In the response provided by the applicant to RAI 3.0-10 LP, the staff's concerns relevant to MIC were not addressed. The staff was concerned that various corrosion mechanisms that would not be active during operation often appear during layup, as water chemistry controls may not be as stringent, particularly in stagnant areas. Industry documents such as EPRI NP-5580, "Sourcebook for Microbiologically Influenced Corrosion in Nuclear Power Plants," indicate that additions of corrosion inhibitors and biocides made after layup are unlikely to be effective, as distribution throughout the system is limited. EPRI NP-5580 also indicates that proper attention to layup is crucial to avoid MIC and during layup, microbial growth may proceed unimpeded as fluid forces that remove attached organisms from pipe or vessel surfaces are absent. Staff is also concerned that corrosion mechanisms that were not active during dry layup may become active when the systems are wetted and returned to operation. To complete its review, the staff again requested the additional information previously requested in RAI 3.0-10 LP, on inspections performed or planned to determine that MIC is not a concern for systems subject to conditions that promote MIC. The staff originally proposed this as URI 3.0-5 LP. The staff discussed this issue with the applicant in follow-up teleconferences. The following is a disposition of the resolution of the issues in the staff follow-ups and subsequent applicant submittals.

By letter dated May 27, 2005, the applicant referenced the response to RAI 3.0-10 LP included in letter dated May 18, 2005, to address MIC. In the applicant's response by letter dated May 18, 2005, the applicant clarified that the raw water piping is susceptible to MIC and the primary method used for MIC control is routine injection of biocides. The applicant stated that this treatment method has been effective in controlling MIC for in-service raw water piping. For systems not in service during the extended outage the piping was inspected and evaluated. The applicant stated that the majority of the raw water piping was in a dry layup condition and has been inspected and found to have adequate wall thickness, with two exceptions. As identified by the applicant, the portions of the RHRSW system in the reactor building that contained moisture required replacement due to inadequate wall thickness. Similarly, approximately 3,000 feet of large bore and small bore RCW piping requires replacement due to inadequate wall thickness.

The staff reviewed the applicant's response and found the response acceptable. The applicant clarified that raw water piping susceptible to MIC during the extended outage has either been replaced or inspected to verify that adequate wall thickness exists. In addition, there is reasonable assurance that the mitigative programs will be effective to preclude future MIC and potential latent aging effects due to MIC in all systems subject to layup during the extended outage, including systems containing raw water, will be detected and corrected by future periodic inspections. All issues related to RAI 3.0-5 LP are resolved.

3.7.1.5 Transition from Layup Program to System Cleanliness Verification Program

The system cleanliness verification program is not addressed in the LRA nor in February 19, 2004, letter containing the attachment, "Evaluation of BFN Unit1 Layup and Preservation Program." NRC quarterly integrated inspection report 05000259/2004006 states that on March 22, 2004, the applicant decided to remove all Unit 1 systems from layup. This decision was based on the need to transition to a system Cleanliness Verification Program. According to NRC quarterly integrated inspection report 05000259/2004007, this program is intended to replace the previous equipment layup program that has been in place since the unit was shutdown. This report also stated that, under the new program, the assigned system and component engineers, along with chemistry personnel, would perform a series of inspections of Unit 1 systems to identify any system degradation or special requirements to support Unit 1 recovery. It is the staff's understanding that transition to the newer program was still in progress at the time of the inspection period on July 10, 2004.

In RAI 3.0-11 LP, dated December 16, 2004, the applicant was requested to clarify if this series of inspections is part of the One-Time Inspection Program that is going to be implemented prior to Unit 1 restart. If the one-time inspections are different from or in addition to the cleanliness verification program inspections, the applicant was requested to so clarify. Also, it is not clear to the staff if this system cleanliness verification program includes inspections on components that were replaced or repaired. The applicant was requested to provide additional information as to what type of inspections have been or will be performed by the system Cleanliness Verification Program (CVP).

In its response to RAI 3.0-11 LP, the applicant stated that inspections performed under the CVP are not part of the one-time LRA inspections or credited as part of the license renewal application. The applicant clarified that to facilitate Unit 1 restart activities, Unit 1 systems have been removed from the layup program. It is not possible to maintain the layup program and perform the required field work needed for restart of Unit 1.

The applicant stated that the purpose of the CVP is to (1) verify, through cleanliness verification of all internal and external surfaces of piping systems and metallic components, that the requirements for fluid (gas or liquid) system internal and external cleanliness are in accordance with TVA and industry standards; and (2) provide the detailed remedial cleaning instructions for internal and external surfaces of piping systems and metallic components whose internal and external surface cleanliness does not meet respective cleanliness criteria as a result of extended layup, or work activity.

The CVP activities are applicable to all Unit 1 steam, water, air, gas and oil piping systems and components that receive a formal return to service in accordance with the Unit 1 Restart Test Program System Preoperational Checklist. The applicant clarified that the only Unit 1 systems excluded from this program are those that are currently in service or have been in service supporting Units 2 and 3.

The applicant also stated that CVP inspections are performed to ensure internal and external system cleanliness and that foreign material control program requirements are met. Visual inspections aided by boroscopes are performed to identify any needed remedial cleaning or flushing activities. If inspection reveals evidence of piping degradation, a problem evaluation report is initiated and entered into the Corrective Action Program. An engineering evaluation is performed to ensure that the system is capable of operation through the extended period. The applicant further stated that the inspections performed by the CVP are not a part of the one-time LRA inspections; nor are they a part of the license renewal process.

The staff reviewed the applicant's response to RAI 3.0-11 LP and found that the response is reasonable and acceptable because the applicant provided sufficient information on system cleanliness inspections and clarified that cleanliness inspections are different from the one-time inspections credited for license renewal. The applicant credits visual inspections aided by boroscopes to detect and correct degradation during the transition period between layup and restart. Both external and internal inspections are performed to industry standards as part of the system Cleanliness Verification Program. Internal inspections to recognized industry standards should be adequate to detect degradation during the transition period between layup and restart.

3.7.2 Reactor Vessel internals and Reactor Coolant System

3.7.2.1 Reactor Recirculation System (068)

Summary of Technical Information in the Application.

The applicant provided a summary of its evaluation of the Unit 1 layup and preservation program in LRA Section 3.0.1. The applicant's specific AMRs for the reactor recirculation system (068) of Unit 1 that are exposed to wet layup environment are given in Table 2 of the applicant's letter, "Evaluation of the BFN Unit 1 Lay-up and Preservation Program," Revision 1, dated February 19, 2004. The applicant identified several aging effects of the applicable materials of the reactor recirculation system that are exposed to the wet layup environment. These components extend from the reactor vessel outlet nozzle, through the valves and pumps, to the reactor vessel inlet nozzle. Also included are components within the reactor recirculation motor generator set oil system and instrument tubing and piping outside the drywell.

In Section 4.0 of chapter "Mechanical System/Program Evaluation Detail-Wet Layup Program Unit 1" of the February 19, 2004, letter, the applicant identified the following aging effects associated with stainless steel, carbon steel, and copper-alloy materials that are exposed to a treated-water environment during the wet layup period of Unit 1.

- general corrosion
- crevice corrosion
- pitting corrosion
- galvanic corrosion
- selective leaching

In Table 2, "Evaluation of BFN Unit 1 Layup and Preservation Program," Revision 1, the applicant provided a summary of AMRs for the reactor recirculation systems of Unit 1 that are within the boundary of the wet layup program. These AMRs are not addressed in the GALL Report. The staff also identified areas where additional information or clarification was needed. The staff's evaluation of the applicant's responses to those RAIs is included below.

Crevice and Pitting Corrosion. The staff, after the review of the applicant's submittal, determined that aging effects due to crevice and pitting corrosion of the reactor recirculation system, are possible unless stringent control on the RCS water is implemented during the wet layup period. The aging effects due to crevice and pitting corrosion on the reactor recirculation system materials (i.e., carbon steel, stainless steel, and copper-alloy materials) can be more pronounced when they are exposed to stagnant conditions during the wet layup rather than the regular service condition. The applicant stated that the reactor recirculation system materials will experience crevice and pitting corrosion when the dissolved oxygen content in the RCS water exceeds 100 ppb, and the choride and sulphate contents exceed and 150 ppb with stagnant or low flow conditions during the wet layup period. In Table 2 of the applicant's submittal, "Evaluation of the BFN Unit 1 Lay-up and Preservation Program," Revision 1, the applicant claims that it will manage this aging effect by CI-13.1 Chemistry Control Program. The cold shutdown impurity limits for conductivity, chloride, and sulfate given in CI-13.1 (1.5. µS/cm, 15 ppb, 15 ppb) are more restrictive than those given in the EPRI BWR Water Chemistry Guidelines (TR-103515-R2, page 4-6, Table 4-2) for "Reactor Water - Cold Shutdown." The staff found that the implementation of the Chemistry Control Program would enable the applicant to subsequently mitigate the crevice and pitting corrosion in the reactor recirculation system components.

Selective Leaching. The staff, after the review of the applicant's submittal, determined that the aging effect due to selective leaching of reactor recirculation system components fabricated from copper-alloy material used in a treated-water environment require aging management for selective leaching for the period of extended operation for the Unit 1 layup systems. The applicant stated that copper-zinc alloys containing greater than 15 percent zinc in a treated-water environment are susceptible to selective leaching, while copper alloys with a copper content in excess of 85 percent resist dezincification. The applicant currently credits the One-Time Inspection Program and the Selective Leaching of Materials Program; but, requires no additional aging management of Unit 1 due to the wet layup condition as shown in Table 2 of its February 19, 2004, letter. The staff found this acceptable because the One-Time Inspection Program and Selective Leaching Program will be just as effective to detect and manage selective leaching on the Unit 1 wet layup systems as it is on systems not in wet layup in BFN.

Loss of Material Due to General Corrosion. General corrosion of carbon and low-alloy steel in treated water is an aging mechanism that must be managed for the period of extended operation for the Unit 1 layup Systems. The applicant identified the Chemistry Control Program, the One-Time Inspection Program and ASME Section XI Subsections IWB, IWC and IWD Inspection Program. The Chemistry Control Program mitigates general corrosion by minimizing dissolved oxygen, thus, reducing the effect of general corrosion as an internal aging effect. The applicant's one-time inspection will ensure that general corrosion has been controlled and the ASME Section XI inspections will ensure that the affected components continue to perform their required function during the period of extended operation.

Loss of Material Due to Galvanic Corrosion. Galvanic corrosion of carbon and low-alloy steel in treated water is an aging mechanism that must be managed for the period of extended operation for the Unit 1 layup systems. The applicant identified the Chemistry Control Program, the One-Time Inspection Program, and ASME Section XI Subsections IWB, IWC and IWD Inspection Program. The Chemistry Control Program minimizes galvanic corrosion by controlling dissolved oxygen, chlorides, conductivity, and PH. The applicant's one-time inspection will provide verification that galvanic corrosion has been managed during the Unit 1 wet layup period and the ASME Section XI inspections will ensure that the affected components continue to perform their required function during the period of extended operation.

As a result of the Unit 1 restart efforts, the applicant is in the process of replacing several components and is conducting numerous inspections. Below is a description of some of the restart efforts that impact the recirculation system and provide additional confidence that Unit 1 will be adequately managed so that the intended functions of the reactor recirculation system are maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Recirculation System Piping. During the restart efforts on Unit 1, several components will be replaced, obviating the need to be concerned about degradation of these components during the wet-layup period. In RAI 3.1.2.4-6, dated December 1, 2004, the staff requested that the applicant discuss whether the recirculation system piping had experienced any cracking in the past. The applicant responded in part that no recirculation system piping welds less than NPS 4 were identified as having cracking or crack indications in the inservice records. The applicant also stated that during the Unit 1 recovery efforts the recirculation system piping greater than NPS 4 is being replaced with IGSCC-resistant piping (316NG or 316L). According to the applicant, this includes all welds that it identified as having IGSCC indications. In order to clarify the extent of piping replacement in the reactor recirculation system, the staff requested the applicant to discuss replacement of piping less than NPS 4 in a follow up to RAI 3.1-1. The applicant responded by letter dated January 20, 2005, and stated that all piping of the reactor recirculation system (068) is being replaced with the exception of small sections of the 3/4-inch and 1-inch piping on each side of the system 068 penetrations on LR drawing 1-47E817-1-LR.

Heat Exchangers. All heat exchangers that are not being replaced due to design changes are being inspected. Inspection will include 100 percent eddy current testing of tubes. SR heat exchangers will have their shell casing ultrasonically tested for thickness. The applicant also stated that visual inspections of the heat exchangers for pitting or erosion are performed when manway covers are removed or the connecting piping is replaced.

Valves. Valves within the piping systems were reviewed to determine whether the valves needed to be replaced or refurbished. During the Unit 1 restart effort, approximately 3000 valves will be replaced. The applicant also estimated that approximately 1000 valves will be tested and refurbished.

Conclusion. The staff, after reviewing the applicant's submittal, concluded that the aforementioned aging effects do not cause any additional degradation of components in the reactor recirculation system during the wet layup period at Unit 1. The staff believes that the relevant critical variables that may cause any additional degradation due to these aging effects are adequately managed during the wet layup period. If by chance some additional degradation occurred in the reactor recirculation system, the applicant's restart activities should be effective in identifying and correcting issues prior to start up.

3.7.2.2 Reactor Vessel (RV), Reactor Vessel Internals (RVIs)

Summary of Technical Information in the Application.

The applicant's specific AMRs for the RV and RVIs at Unit 1 that are exposed to the wet layup environment are given in Table 2 of the applicant's supplemental submittal, dated February 19, 2004, "Evaluation of the Unit 1 Layup and Preservation Program, Revision 1." The applicant identified several aging effects applicable to the materials in the RV and RVIs that are exposed to the wet layup environment during the extended outage.

The components in the RV and RVIs include RV attachment welds, reactor closure studs and nuts, RV heads, flanges and shells, RV nozzles and safe ends, RV penetrations, RVIs core shroud and core plate, RVIs core spray lines and spargers, RVIs dry tubes and guide tubes and RVIs jet pump assemblies.

In Section 4.0 of the supplemental submittal dated February 19, 2004, the applicant evaluated the following aging effects that are associated with stainless steel materials when they are exposed to RCS treated-water environment during the wet layup period at Unit 1.

- pitting corrosion
- crevice corrosion
- MIC
- SCC
- thermal aging
- neutron embrittlement
- stress relaxation
- particulate fouling

Technical Staff Evaluation of Aging Effects

In Table 2 of the supplemental submittal dated February 19, 2004, the applicant provided a summary of AMRs for the RV and RVIs at Unit 1 that are within the boundary of the wet layup program. These AMRs are not addressed in the GALL Report. The staff also identified several areas where additional information or clarification was needed. The staff issued RAIs to the applicant regarding the wet layup issues. The staff's evaluation of the applicant's submittal and its responses to the RAIs are addressed below.

Pitting and Crevice Corrosion. The staff, after the review of the applicant's submittal, determined that the aging effects due to pitting and crevice corrosion of the RCS pressure and non-pressure boundary components could have been significantly affected during the wet layup period, unless stringent control on the RCS water was implemented during the wet layup period. The RVs and RVIs could have been subjected to more frequent stagnant conditions during the wet layup period than during regular service conditions. Therefore, aging effects due to pitting and crevice corrosion on the RV and RVIs materials can be more pronounced when they are exposed to stagnant conditions during the wet layup period. The applicant stated that the RV materials may have experienced pitting when the RCS water dissolved oxygen concentration exceeded 100 ppb and the chloride or sulfate concentrations exceeded 150 ppb during the wet layup period. However, crevice corrosion could have occurred when the dissolved oxygen content in the RCS water exceeded 100 ppb. In Table 2 of the submittal, the applicant stated that it managed these aging effects by CI-13.1 Chemistry Program. The cold shutdown impurity limits for conductivity, chloride and sulfate given in CI-13.1 [1.5 µS/cm), 15 ppb, 15 ppb] are more restrictive than those given in the EPRI BWR Water Chemistry Guidelines (TR-103515-R2, page 4-6, Table 4-2). These guidelines are applicable for RCS water when the plant is in cold shutdown condition.

In RAI 3.0-1 LP(a), the staff requested that the applicant identify the differences between the chemistry program(s) implemented in the RCS system during the wet layup period at Unit 1 and the chemistry program to be implemented in the RCS system at Unit 1 during the period of extended operation.

In its response to NRC RAI 3.0-1 LP(a), by letter dated October 8, 2004, the applicant stated that the RCS water was monitored for conductivity, chloride and sulfate concentrations in accordance with the requirements of CI-13.1. The chemistry control limits implemented during the wet layup period at Unit 1 are the same as the chemistry control limits utilized by Units 2 and 3 during cold shutdown conditions for refueling and maintenance outages. The selected BFN impurity limits are consistent with the limits for cold shutdown that are contained in BWRVIP-79, "BWR Water Chemistry Guidelines," (EPRI Report TR-103515-R2, February 2000), which is consistent with the GALL AMP XI.M2, "Water Chemistry," and the Chemistry Control Program. The chemistry program implemented during the period of extended operation for Unit 1 is the same program as that for Units 2 and 3 during power operation conditions.

The staff reviewed the response and found that implementation of a Chemistry Control Program that is more restrictive than GALL AMP XI.M2, would enable the applicant to mitigate pitting corrosion effectively in the RV and RVIs during the wet layup period at Unit 1.

The staff contended that if the dissolved oxygen content exceeded 100 ppb during the wet layup period, crevice corrosion of the RVIs could have occurred. In order to ensure that crevice corrosion is not occurring in the RV and RVIs, the staff requests that the applicant confirm that the dissolved oxygen content in the RCS water did not exceed 100 ppb during the wet layup period. This staff issue was resolved by the applicant's subsequent response and submittals (see SER Section 3.7.2.2 below).

In RAI 3.0-1 LP(b), the staff requested that the applicant discuss the criteria (e.g., guidelines) used to maintain the chemistry of the fluid in the wet layup systems, the chemistry parameters monitored, and the frequency of the monitoring/trending.

In its response to RAI 3.0-1 LP(b), by letter dated October 8, 2004, the applicant stated that during the wet layup period reactor water was monitored in accordance with the requirements specified in Table 5 of the CI-13.1. The impurity limits for conductivity, chloride, and sulfate given in CI-13.1 were 1.5. µS/cm, 15 ppb and 15 ppb, respectively. The applicant also stated that sampling was performed once every two weeks, and the monitoring and trending results demonstrated that the RCS water was maintained within its impurity limits during the wet layup period.

Since the verification frequency of the RCS water chemistry is once every two weeks during the wet layup period, the staff determined that pitting and crevice corrosion in the RV and RVIs can occur if they are exposed to higher concentrations of chlorides and sulfates due to a leak in the primary systems. The staff issued follow-up RAI 3.0-1 LP (b), requesting that the applicant provide information regarding its past experience related to any sudden increase in concentration of chlorides and sulfates in the RCS water during the wet layup period, and the corrective actions taken to prevent impurities migrating into crevices in the RV and RVIs. The staff further requested that the applicant identify the crevice locations in the RV and RVIs that will not be replaced and where accumulation of aggressive ions such as chlorides and sulfates inside the crevice could have enhanced the likelihood of pitting and crevice corrosion during the wet layup period at Unit 1. The staff also requested that the applicant provide information regarding the type of inspection it intends to use in identifying the aging effects due to pitting and crevice corrosion in the RV and RVIs prior to Unit 1 restart and during the extended period of operation.

In its response to follow-up RAI 3.0-1 LP(b), by letter dated January 31, 2005, the applicant stated that during the wet layup period at Unit 1, the RCS water was operated as a closed-loop system using the RWCU system. Impurities (i.e., chlorides and sulfates) in the make-up water system at Unit 1 can potentially contaminate the RCS water. Condensate water was used for make-up water. If any impurities were detected, a new ion exchange resin would be applied to the RWCU system demineralizer. Since the RCS water would be processed approximately 1.5 times a day through the RWCU system, the applicant claimed that verification of RCS water chemistry every two weeks would be adequate in detecting the impurities. The applicant found no occurrences of sudden increase in concentration of impurities (i.e., chlorides and sulfates) in the RCS water during the wet layup period at Unit 1. The applicant stated that the impurities were maintained at acceptable levels (< 15 ppb) during the wet layup period. Based on stringent chemistry control, the applicant claimed that the RV and RVIs were less susceptible to pitting corrosion during the wet layup period. The applicant also proposed to perform inspections (discussed below) on the RV and RVIs prior to Unit 1 restart.

The staff reviewed the response and found it acceptable because the applicant implemented a Chemistry Control Program that is more restrictive than GALL AMP XI.M2. Since the impurities (i.e., chlorides and sulfates) in the RCS water were kept below the acceptable levels of 15 ppb, the RV and RVIs were less susceptible to pitting during the wet layup period.

In RAI 3.1-3 LP, the staff requested that the applicant provide details on any inspection plans for the RV and RVIs prior to Unit 1 restart.

In its response to RAI 3.1-3 LP, by letter dated August 23, 2004, the applicant stated that the RV and its components will be inspected in accordance with the requirements of the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program. The RVIs will be inspected in accordance with the requirements of relevant BWRVIP guidelines. The following list includes the RVIs and the applicable BWRVIP reports approved by the staff (with the exception of BWRVIP-76).

- BWRVIP-18-----Core Spray
- BWRVIP-25-----Core Plate
- BWRVIP-26-----Top Guide
- BWRVIP-27-A--Standby Liquid Control
- BWRVIP-38-----Shroud Support
- BWRVIP-41-----Jet Pump

- BWRVIP-47-----Lower Plenum (CRD, Incore)
- BWRVIP-48---- Vessel Attachment Welds
- BWRVIP-49-----Instrumentation Penetrations
- BWRVIP-76-----Core Shroud (under staff's review)

The applicant stated that the core shroud access hole covers will be examined in accordance with GE SIL 462, Revision 1. The applicant stated that the access hole covers for Unit 1 are cracked essentially 360 degrees around and will be replaced prior to Unit 1 restart.

The staff reviewed the response and found it acceptable because of the implementation of the ISI program, which is an established AMP that is based on compliance with the staff's ISI requirements in 10 CFR 50.55a. This program has appropriate requirements for inspecting the RV components prior to Unit 1 restart. The RVIs will be inspected in accordance with the requirements of applicable BWRVIP guidelines, thus enabling the applicant to identify pitting corrosion in the RVIs in a timely manner so that proper corrective actions could be taken to ensure their structural integrity prior to Unit 1 restart.

The staff's position is that if the dissolved oxygen content exceeds 100 ppb during the wet layup period, crevice corrosion of the RVIs could occur. In order to ensure that crevice corrosion is not occurring in the RV and RVIs, the staff requests that the applicant confirm that the dissolved oxygen content in the RCS water did not exceed 100 ppb during the wet layup period (Unresolved Item 3.7.2.2-1 in the applicant's response dated May 27, 2005). The staff followed this issue with the applicant in follow-up teleconferences. The following is a disposition of the resolution of the issues in the staff follow-ups and subsequent applicant submittals.

To confirm that the crevice locations in RVIs are not susceptible to corrosion, the staff requests that the applicant identify these locations and provide information as to how it uses the applicable BWRVIP inspection guidelines to detect any crevice corrosion of the RVIs prior to Unit 1 restart. (Unresolved Item 3.7.2.2-2 in the applicant's response dated October 13, 2005).

In its response, by letter dated May 27, 2005, the applicant indicated that during the wet layup period the RCS water was open to the atmosphere; therefore, the dissolved oxygen content in RCS water was expected to increase to 8 ppm. The staff requested that the applicant provide information regarding the implementation of the BWRVIP inspection guidelines to detect crevice corrosion of the RVIs prior to Unit 1 restart. In its response, the applicant also listed the following systems that have crevice type configurations, and proposed to implement appropriate BWRVIP inspection guidelines to monitor the aging effect due to crevice corrosion in these systems. The systems with crevice configuration include: (1) core spray; (2) jet pump assembly; (3) top guide; (4) control rod guide, and (5) core plate. The staff found the applicant's response acceptable because the inspection frequency and the inspection techniques specified in the respective BWRVIP guidelines, and the augmented inspection for the top guide (see TLAA SER Section 4.2.8.2) will adequately identify the crevice corrosion in the RVIs components so that corrective actions can be taken prior to Unit 1 restart, and after inservice inspection in accordance with BWRVIP guidelines. The staff considers these issues resolved.

Conclusion. The staff, after reviewing the applicant's submittal, and its responses to RAIs, concluded that the aging effect due to pitting corrosion had not caused any degradation of the RV and RVIs during the wet layup period at Unit 1. If any additional degradation occurred due to pitting corrosion in the RV and RVIs, the applicant's restart activities should be effective in identifying and correcting issues prior to Unit 1 restart. The staff concluded that the aging effect due to crevice corrosion in the RVs and RVIs during the wet layup can be ascertained.

The applicant stated that the following aging effects are less likely to occur in the RV and RVIs and, as such, they do not require an AMP. This assessment was based on the fact that the conditions (stated below for each aging effect) in the RV and RVIs are less conducive for these aging effects to cause any degradation during the wet layup period.

- MIC
- SCC
- thermal aging
- neutron embrittlement
- stress relaxation

MIC. In Table 2 of the submittal, the applicant stated that MIC is unlikely to occur in treated water systems where sulfates are less than 150 ppb, and at temperatures greater than 210 °F or pH greater than 10. The applicant claimed that Unit 1 layup systems contain treated water with little or no contamination. A review of BFN's work orders identified no instances where MIC was a failure mechanism for any components in the scope of license renewal for the RV and RVIs. The applicant stated that the RV and RVIs will not be affected by the aging effect due to MIC during the wet layup period. Based on the review of the submitted information, and in the absence of any evidence that indicates contamination in Unit 1 systems during the wet layup period, the staff believes that the RV and RVIs have not degraded due to MIC during the wet layup period at Unit 1.

Stress Corrosion Cracking. In Table 2 of the applicant's submittal, the applicant stated that for treated-water environments, stainless steel and nickel alloys are susceptible to SCC in the presence of chlorides or sulfate concentrations greater than 150 ppb and when the dissolved oxygen exceeds 100 ppb at temperatures greater than 140 °F. The applicant claimed that limiting the chloride and sulfate concentrations to less than 150 ppb, and the dissolved oxygen to less than 100 ppb eliminates the potential for SCC of the stainless and nickel alloys' internal surfaces. The normal temperature of the RV systems is less than 140 °F during the wet layup period. The applicant concluded that the RV and RVIs have not degraded due to SCC during the wet layup period.

In NRC RAI 3.0-1 LP b(4), the staff requested that the applicant provide information related to any addition of hydrogen inside the vessel and RCS systems to reduce the oxidizing nature of RCS water, which in turn reduces the occurrence of SCC of the RV and RVIs. In its response to RAI 3.0-1 LP b(4), by letter dated January 31, 2005, the applicant stated that no hydrogen was added to any of the RCS systems during the wet layup period. However, hydrogen will be added to the RCS systems during normal power operation at Unit 1. The staff found that the applicant's response is acceptable because during the wet layup period, the temperature of the RV and RVIs was less than 140 °F; therefore, the RVI and RVIs were less likely to experience SCC.

In RAI 3.0-1 LP b(5), the staff requested that the applicant provide information related to the measurement of ECP of the reactor coolant, which will provide information on the oxidizing nature of the RCS water. In its response to RAI 3.0-1 LP b(5), by letter dated January 31, 2005, the applicant stated that no ECP measurements were made during the wet layup period. Since the RCS temperature is kept below 140 °F during the wet layup period, aging effects of the RV and RVIs due to SCC is less likely. The staff found that the applicant's response of not measuring ECP values of the RCS water during the wet layup period is acceptable because SCC is less likely to occur when the RCS temperature was kept below 140 °F during the wet layup period at Unit 1.

Thermal Aging. The applicant stated that wrought austenitic stainless steel is not susceptible to thermal embrittlement when exposed to normal nuclear plant operating environments. However, CASS materials are susceptible to thermal embrittlement depending upon material composition and time at high temperatures. CASS materials subjected to temperatures greater than 482 °F are susceptible to thermal aging. The normal temperature of the RCS system during the wet layup period at Unit 1 is less than 482 °F; therefore, the applicant claimed that CASS materials did not experience degradation due to thermal aging during the wet layup period. The staff, after the review of the submittal, concluded that the CASS materials did not degrade due to thermal aging during the wet layup period.

Neutron Embrittlement. The applicant stated that the carbon and low-alloy steel RV beltline region of the Unit 1 was not subjected to neutron fluence during the wet layup period; therefore, the degradation due to neutron embrittlement is not considered a potential aging effect. The staff agrees with this disposition, and concluded that the RV beltline region did not degrade due to neutron embrittlement during the wet layup period.

Stress Relaxation. The applicant stated that stress relaxation is a potential aging mechanism for bolting/fasteners with the RV and RVIs. The applicant claimed that the bolting/fasteners did not degrade due to stress relaxation during the wet layup period. The staff believes that during the wet layup period at Unit 1 the bolting/fasteners were not subject to any service-related loading conditions; consequently, they did not experience degradation due to stress relaxation.

Conclusion. The staff, after reviewing the applicant's submittal and its responses to RAIs, concluded that the aging effect due to pitting corrosion did not cause any degradation of the RV and RVIs during the wet layup period at Unit 1. If any additional degradation occurred due to pitting corrosion in the RV and RVIs, the applicant's restart activities should be effective in identifying and correcting issues prior to Unit 1 restart. The staff concluded that the aging effect due to crevice corrosion in the RVs and RVIs during the wet layup can be ascertained.

The staff, after reviewing the applicant's submittal, concluded that other aging effects did not cause any degradation in the RV and RVIs during the wet layup period at Unit 1. The staff believes that the relevant critical variables that cause any degradation due to these aging effects were adequately controlled during the wet layup period. These critical variables include reactor water temperature, RCS water chemistry, neutron fluence and any service-induced loading conditions. Based on the information provided by the applicant thus far, the staff concluded that these critical variables stayed dormant and did not cause any degradation of the RV and RVIs during the wet layup period. If any additional degradation occurred in the RV and RVIs, the applicant's restart activities should be effective in identifying and correcting issues prior to Unit 1 restart.

3.7.3 Engineered Safety Features

3.7.3.1 Engineered Safety Features Systems in Dry Layup

3.7.3.1.1 High Pressure Coolant Injection System

Technical Staff Evaluation. The technical staff reviewed the AMR of the HPCI system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The HPCI system is described in LRA Section 2.3.2.3. LRA Table 3.2.2.3 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that the Unit 1 HPCI system was maintained in dry layup during the extended shutdown. The applicant's February 19, 2004, submittal described the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 1 of the applicant's February 19, 2004, supplement on wet layup provides the AMR of the HPCI system components within the scope of license renewal and was maintained in dry layup conditions. The component types include bolting, condenser, expansion joint, fittings, flexible connectors, gland seal blower, heat exchangers, piping, pumps, restricting orifices, strainers, tanks, traps, tubing, turbines, and valves.

The February 19, 2004, submittal describes the internal environment of the system as being maintained at less than 60 percent RH de-humidified air. The external environment was inside air.

For the Unit 1 HPCI system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in air/gas (internal) or inside air (external) environments are subject to a loss of material due to general corrosion. Cast iron and cast iron alloy components in air/gas (internal) or inside air (external) environments are subject to a loss of material due to general corrosion. Elastomer components in inside air (external) environments are subject to hardening and loss of strength due to elastomer degradation. No aging effects are identified for stainless steel, nickel-alloy, and copper-alloy components in air/gas (internal) or inside air (external) environments. No aging effects are identified for glass components in inside air (external) environments. No aging effects are identified for elastomers in air/gas (internal) environments.

During its review, the staff determined that additional information was needed to complete its review.

In Table 1 of the February 19, 2004, submittal, for the HPCI system (73) and core spray system (75), the Unit 1 layup components made of carbon and low-alloy steel as well as cast iron and cast iron alloy in air/gas (internal) or inside air (external) environments are subject to general corrosion during the period of extended outage. In the LRA AMR, the same aging effect is also identified for the same components in air/gas (internal) and inside air (external) environments. Because of the uncertainty of the dryness of air environments, the staff requested, in RAI 3.2-1

LP, the applicant to assure that the above layup air environments for these components are not any more aggressive than their counterparts in the plant operating environments, and that no additional aging effects would need to be considered. By letter dated October 8, 2004, the applicant stated that the HPCI system (73) was drained and laid up dry per 1-GOI-100-13.A and 0-TI-373. The core spray system (75) was drained and laid up dry per 1-GOI-100-13.17 and 0-TI-373. The air/gas environments for these systems were maintained to less than 60 percent humidity with dehumidifiers. The applicant stated that both the normal and layup environments were relatively dry (no pooling) air/gas environments. In addition, the heating and ventilation in the reactor building was maintained during layup; therefore, the inside air environment for systems 73 and 75 did not significantly change systems 73 and 75. Based on the above, the staff concluded that the layup air environments for the above components are not any more aggressive than their counterparts in the plant operating environments, and the aging effects for these components in the normal operating and layup environments are the same. RAI 3.2-1 LP is, therefore, resolved.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the HPCI system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 HPCI system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 1 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the HPCI system.

- One-Time Inspection Program (B.2.1.29)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7 and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

As stated in Table 1 of the February 19, 2004, submittal, for the HPCI system (73) and core spray system (75), the Unit 1 layup components made of carbon and low-alloy steel as well as cast iron and cast iron alloy in air/gas (internal) environments are subject to general corrosion during the period of extended outage. For the LRA AMR, the same aging effect is identified for the same components in an air/gas (internal) environment, with the One-Time Inspection Program credited as the only AMP for managing the identified aging effects. No additional AMPs were proposed for the layup program.

In RAI 3.2-2 LP, the staff requested the applicant to provide justification that additional inspection programs were not required for possible unintended moisture conditions accumulated in the above components of both the HPCI system (73) and the core spray system (75), during the period of extended outage. By letter dated October 8, 2004, the applicant stated that pooled water is not anticipated for the portions of Systems 73 and 75 addressed in Table 1 per the layup program 0-TI-373. To ensure detection of possible material degradation, the applicant stated that the restart inspection will be performed prior to the Unit 1 restart instead of at the end of the current licensing period to verify that the layup program has been adequate in protecting the material from significant degradation. Based on the lack of aggressive environments associated with the components in Systems 73 and 75, the staff found that the applicant's initiative in performing restart inspections for possible material degradation prior to Unit 1 restart is acceptable. RAI 3.2-2 LP is, therefore, resolved.

To ensure the general acceptability of the One-Time Inspection Program in managing loss of material due to general corrosion, the staff requested in RAI 3.0-2 LP that the applicant provide detailed information of the One-Time Inspection Program, and provide justification that it is adequate for managing the aging effects for the components within the dry layup systems. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.0.3.3.5.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff found that the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 HPCI system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 HPCI system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.3.1.2 Core Spray System

Technical Staff Evaluation. The technical staff reviewed the AMR of the core spray system (75) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The core spray system is described in LRA Section 2.3.2.5. LRA Table 3.2.2.5 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that Unit 1 core spray system was maintained in dry layup during the extended shutdown. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 1 of the applicant's February 19, 2004, submittal provides the AMR of the core spray system components within the scope of license renewal and maintained in dry layup conditions. The component types include bolting, fittings, piping, pumps, restricting orifices, strainers, tanks, tubing, and valves.

The February 19, 2004, submittal describes the internal environment of the system as being maintained at less than 60 percent RH de-humidified air. The external environment was inside air.

For the Unit 1 core spray system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel, and cast iron and cast iron alloy. Components in air/gas (internal) or inside air (external) environments are subject to a loss of material due to general corrosion. No aging effects are identified for stainless steel, aluminum alloy, and polymer components in air/gas (internal) or inside air (external) environments.

During its review, the staff determined that additional information was needed to complete its review.

In Table 1 of the February 19, 2004, submittal for the core spray system (75), the Unit 1 layup components made of carbon and low-alloy steel, as well as cast iron and cast iron alloy, components in air/gas (internal) or inside air (external) environments are subject to general corrosion during the period of extended outage. In the LRA AMR, the same aging effect is also identified for the same components in air/gas (internal) and inside air (external) environments. Because of the uncertainty of the dryness of air environments, the staff requested, in RAI 3.2-1 LP, that the applicant assure that the layup air environments for these components are not any more aggressive than their counterparts in the plant operating environments, and that no additional aging effects would need to be considered. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.7.3.1.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the core spray system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 core spray system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 1 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the core spray system.

- One-Time Inspection Program (B.2.1.29).
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7 and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

As stated in Table 1 of the February 19, 2004, submittal, for the core spray system (75), the Unit 1 layup components made of carbon and low-alloy steel as well as cast iron and cast iron alloy in air/gas (internal) environments are subject to general corrosion during the period of extended outage. For the LRA AMR, the same aging effect is identified for the same components in an air/gas (internal) environment, with the One-Time Inspection Program credited as the only AMP for the material/environment combination. No additional AMPs were proposed for the counterpart components included in the layup program. In RAI 3.2-2 LP, the staff requested the applicant to provide justification that additional inspection programs were not required, for possible unintended moisture conditions accumulated in the system components during the period of extended outage. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.7.3.1.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 core spray system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 core spray system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.3.2 Engineered Safety Features Systems in Various Wet Environments

3.7.3.2.1 Containment System

Technical Staff Evaluation. The technical staff reviewed the AMR of the containment system (64) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The containment system is described in LRA Section 2.3.2.1. LRA Table 3.2.2.1 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal state that the portions of Unit 1 containment system within the scope of BFN license renewal were not incorporated into the BFN layup program, but were included in the evaluation. The components within the scope of BFN license renewal for the containment system (64) saw treated (torus) water based on the locations or leakage of valves were maintained by the Chemistry Program (CI-13.1) for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 3 of the applicant's February 19, 2004, submittal provides the AMR of the containment system components within the scope of license renewal that were not incorporated into the BFN wet layup program. The component types include bolting, duckwork, heat exchangers, fire dampers, flexible connectors, fittings, piping, strainers, traps, tubing, and valves.

The February 19, 2004, submittal identified treated water as the internal environment of the system, and the external environment was inside air, outside air, buried, and treated water.

For the Unit 1 containment system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal and external) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) and outside air (external) environments are subject to loss of material due to general corrosion. Carbon and low-alloy steel components in buried (external) environments are subject to loss of material due to general, crevice, and pitting corrosion, and MIC. Stainless steel components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion. Nickel-alloy components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion. Elastomer components in inside air (external) and outside air (external) environments are subject to hardening and loss of strength due to elastomer degradation (ultraviolet radiation).

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates components in the containment system (64), HPCI system (73), and core spray system (75) that are exposed to an air/gas (internal) environment during normal operation, whereas their counterpart environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of these systems may have been exposed to an internal environment of moist air. The table also states that the evaluation for treated water encompasses the aging effects for a moist air environment in these systems. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the treated-water environment would encompass that of the aging effects for a moist air environment in these systems, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated-water environment during normal operation. By letter dated October 8, 2004, the applicant stated that Table 3 addresses the aging management for portions of several systems (including containment, HPCI, and core spray systems) laid up in a wet environment. Due to closure sequence, closure timing, and possible leakage past the double isolation valves or two drain valves for these systems, it is assumed that an air/gas environment with an uncertain amount of moisture was trapped between the double isolation valves. The trapped moisture between the double isolation valves was considered the same (i.e., raw or treated water) as was water flowing through the valves prior to closure. The applicant stated that the N/A denotes that this trapped air/gas environment will be evaluated under the corresponding raw or treated water evaluations.

The applicant stated that the evaluation of these moist air environments for the systems addressed in Table 3 identified no additional aging effects other than those identified for the corresponding raw or treated-water environment. The applicant stated that the LRA identified these trapped air environments for one-time (restart) inspections because the extent of corrosion could be quantified. It was not the intent of this AMR to determine the rate of loss of material. The applicant further stated that the restart inspection will be performed prior to Unit 1 restart to verify the material condition.

The staff determined that the applicant had adequately explained the nature of the trapped air/gas environments, and why the evaluation of the aging effects for the treated-water environment in the above three ESF systems would encompass that of the aging effects for a moist air environment in these systems. The applicant also committed to perform a restart inspection prior to Unit 1 restart to verify the material condition of the system components. This is acceptable to the staff; therefore, RAI 3.0-5 LP is closed for Systems 64, 73, and 75.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the containment system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 containment system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the containment system.

- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29).
- Buried Piping and Tanks Inspection Program (B.2.1.31)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.2.2, 3.0.3.1.7, 3.0.3.1.9, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates that components in the containment (64), HPCI (73), and core spray (75) systems were exposed to treated (non-controlled) water environments during the extended outage. Table 3 identified no additional AMPs for these layup systems, other than those AMPs specified in LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the determination by providing the results of any water sampling performed, and discuss whether the systems were stagnant or periodically flowed during the period of extended outage. The staff also requested the applicant to discuss the plans for pre-startup inspections or provide justification that such inspections are not needed. By letter dated October 8, 2004, the applicant stated that the torus and torus attached piping for the containment system (i.e., the torus itself) and HPCI and core spray systems (torus attached piping) saw torus water maintained by CI-13.1 chemistry program, Appendix A, Table 20, for extended periods of time until the torus was drained in the summer of 2003. When filled, the torus is approximately half full of water with the other half ambient air. The torus water was not flowing in that the only significant water movement was relatively infrequent transfers into and out of the Unit 1 torus. The torus on an operating unit cannot be considered "flowing" either. The operating unit's torus would also be nitrogen-inerted. The applicant stated that torus coating touch-up/repair is part of the restart work to be completed while the torus is drained.

The applicant stated that the torus impurity administrative goals for conductivity, chloride, and sulfate given in CI-13.1 are 2.0. µS/cm, 75 ppb, and 75 ppb, respectively, which are within the chemistry specifications. Sampling is performed quarterly. The applicant also stated that the restart inspection will be performed prior to Unit 1 restart to verify the material condition.

Based on the above information, pending the staff's acceptance of the applicant's wet layup program chemistry controls provided in SER Section 3.7.1.1, the staff determined that the applicant had adequately addressed the staff's concerns related to water chemistry existing during layup and pre-startup inspections, for the containment, HPCI, and core spray systems. RAI 3.0-6 LP is, therefore, closed for these three systems.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 containment system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 containment system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.3.2.2 High Pressure Coolant Injection System

Technical Staff Evaluation. The technical staff reviewed the AMR of the HPCI system (73) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The HPCI system is described in LRA Section 2.3.2.3. LRA Table 3.2.2.3 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal state that the Unit 1 HPCI system within the scope of license renewal was not incorporated into the layup program but was included in the evaluation. Based on location, valve leakage, etc., the components within the scope of license renewal for the HPCI system (73) saw treated (torus) water maintained by CI-13.1 chemistry program for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 3 of the applicant's February 19, 2004, submittal provides the AMR of the HPCI system components within the scope of license renewal that were not incorporated into the wet layup program. The component types include bolting, condenser, expansion joint, fittings, flexible connectors, gland seal blower, heat exchangers, piping, pumps, restricting orifices, strainers, tanks, traps, tubing, turbines, and valves.

The LRA and the February 19, 2004, submittal identified treated water as the internal environment of the system, and the external environment was inside air and treated water.

For the Unit 1 HPCI system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal and external) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion. Stainless steel components in treated water (internal) are subject to loss of material due to crevice and pitting corrosion. Nickel-alloy components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion. Copper-alloy components in treated water (internal) are subject to loss of material due to selective leaching, crevice and pitting corrosion, as well as galvanic corrosion. Cast iron and cast iron alloy components in treated water (internal) environments are subject to a loss of material due to general, crevice, pitting, and selective leaching corrosion. Cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion. Elastomer components in inside air (external) environments are subject to elastomer degradation due to ultraviolet radiation.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of the applicant's February 19, 2004, submittal, components in the HPCI system (73) are shown to be exposed to an air/gas internal environment during normal operation, whereas the environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of this system may have been exposed to an internal environment of moist air. The table also states that the evaluation for treated water encompasses the aging effects for a moist air environment in this system. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the treated-water environment would encompass that of the aging effects for a moist air environment in this system, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated-water environment during normal operation. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Sections 3.7.3.2.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the HPCI system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 HPCI system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the HPCI system.

- ASME Section XI Subsections IWB, IWC, & IWD Inservice Inspection Program (B.2.1.4)
- Chemistry Control Program (B.2.1.5)
- BWR Stress Corrosion Cracking Program (B.2.1.10)
- Flow-Accelerated Corrosion Program (B.2.1.15)
- One-Time Inspection Program (B.2.1.29).
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.3, 3.0.3.2.2, 3.0.3.2.5, 3.0.3.2.9, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates that the HPCI system was not formally incorporated into the Unit 1 wet layup program. This system was exposed to treated (non-controlled) water during the extended outage. Table 3 identified no additional AMPs for this layup system, other than those AMPs specified in the LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the determination by providing results of any water sampling performed and to discuss whether the system was stagnant or periodically flowed during the period of extended outage. The staff also requested the applicant to discuss the plans for pre-startup inspections or provide justification that such inspections are not needed. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Sections 3.7.3.2.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 HPCI system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 HPCI system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.3.2.3 Core Spray System

Technical Staff Evaluation. The technical staff reviewed the AMR of the core spray system (75) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The core spray system is described in LRA Section 2.3.2.5. LRA Table 3.2.2.5 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that, Unit 1 core spray system within the scope of license renewal was not incorporated into the layup program, but was included in the evaluation. Based on location, valve leakage, etc., the components within the scope of license renewal for the core spray system (75) saw treated (torus) water for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 3 of the February 19, 2004, submittal provides the AMR of the core spray system components within the scope of license renewal that were not incorporated into the BFN wet layup program. The component types include bolting, condenser, expansion joint, fittings, flexible connectors, gland seal blower, heat exchangers, piping, pumps, restricting orifice, strainers, tanks, traps, tubing, turbines, and valves.

The LRA and the February 19, 2004, submittal identified treated water as the internal environment of the system, and the external environment was inside air and treated water.

For the Unit 1 core spray system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal and external) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion. Stainless steel components in treated water (internal and external) are subject to loss of material due to crevice and pitting corrosion. Aluminum alloy components in treated water (internal) are subject to loss of material due to crevice and pitting corrosion, as well as crack initiation/growth due to stress corrosion cracking. Cast iron and cast iron alloy components in treated water (internal) environments are subject to a loss of material due to general, crevice, pitting, and selective leaching corrosion. Cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of the applicant's February 19, 2004, submittal, components in the core spray system (75) are shown to be exposed to an air/gas internal environment during normal operation, whereas the environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of this system may have been exposed to an internal environment of moist air. The table also states that the evaluation of treated water encompasses the aging effects for a moist air environment in this system. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the treated-water environment would encompass that of the aging effects for a moist air environment in this system, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated-water environment. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Sections 3.7.3.2.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the core spray system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 core spray system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the core spray system.

- ASME Section XI Subsections IWB, IWC, & IWD Inservice Inspection Program (B.2.1.4)
- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29).
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.3, 3.0.3.2.2, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates that the core spray system was not formally incorporated into the Unit 1 wet layup program. This system was exposed to treated (non-controlled) water during the extended outage. Table 3 identified no additional AMPs for this layup system, other than those AMPs specified in LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the determination by providing results of any water sampling performed, and discuss whether the system was stagnant or periodically flowed during the period of extended outage. The staff also requested the applicant to discuss the plans for pre-startup inspections or provide justification that such inspections are not needed. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Sections 3.7.3.2.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant identified appropriate AMPs for managing the aging effects of the Unit 1 core spray system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 core spray system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.3.3 Engineered Safety Features Systems in Various Dry Environments

3.7.3.3.1 Containment Inerting System

Technical Staff Evaluation. The technical staff reviewed the AMR of the containment inerting system (76) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The containment inerting system is described in LRA Section 2.3.2.6. LRA Table 3.2.2.6 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that the Unit 1 containment inerting system was not formally incorporated into the BFN layup program, but was included in the evaluation. The applicant stated that there were no moisture controls for the portions of the Unit 1 containment inerting system within the scope of BFN license renewal. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004, submittal provides the AMR of the containment inerting system components within the scope of license renewal which were not incorporated into the BFN layup program. The component types include bolting, flexible connectors, heat exchangers, fittings, piping, pumps, strainers, traps, tubing, and valves.

The applicant's February 19, 2004, submittal identified air/gas as the internal environment of the system, whereas the external environment was inside air, outside air, buried, and embedded/encased.

For the Unit 1 containment inerting system components, the applicant identified the following materials, environments, and AERMs, where, because of the uncontrolled moist air, aging effects in addition to those requiring management during the period of extended operation were identified: carbon and low-alloy steel components in air/gas (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion. Stainless steel components in air/gas (internal) environments are subject to loss of material due to crevice and pitting corrosion. Nickel-alloy components in air/gas (internal) environments are subject to loss of material due to crevice and pitting corrosion. Copper-alloy components in air/gas (internal) environments are subject to loss of material due to selective leaching, crevice corrosion, pitting corrosion, and galvanic corrosion. Aluminum alloy components in air/gas environments are subject to loss of material due to crevice, pitting, and galvanic corrosion, and crack initiation/growth due to SCC. Cast iron and cast iron alloy components in air/gas (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion, as well as selective leaching. Cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion.

On the basis of its review of the information provided in the LRA, as supplemented by letter dated February 19, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the containment inerting system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 containment inerting system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the containment inerting system.

- One-Time Inspection Program (B.2.1.29).
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7 and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the containment inerting system (76), the applicant stated that inspections will be performed prior to Unit 1 restart for certain components where additional aging effects were identified for the extended outage. These additional aging effects include those identified for carbon and low-alloy steel, stainless steel, nickel alloy, copper alloy, aluminum alloy, and cast iron and cast iron alloy components in system locations where condensation could build up. No descriptions of the inspections were provided. In RAI 3.0-7 LP, the staff requested the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections. By letter dated October 8, 2004, the applicant stated that internal surface monitoring is performed in accordance with the One-Time Inspection Program described in the LRA, Appendix B, Section B.2.1.29. This is the same AMP proposed for managing internal aging effects of components exposed to moist air during the period of extended operation. The staff found the applicant's commitment of performing one-time inspections to be acceptable, and RAI 3.0-7 LP is closed for the containment inerting system. The staff's discussion of the adequacy of the One-Time Inspection Program in managing the identified aging effects for the system components, versus periodic inspections, is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 18 and 27, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 containment inerting system components not incorporated in the dry layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 containment inerting system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.3.3.2 Containment Atmosphere Dilution System.

Technical Staff Evaluation. The technical staff reviewed the AMR of the containment atmosphere dilution system (ADS) (84) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The containment ADS is described in LRA Section 2.3.2.7. LRA Table 3.2.2.7 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that the Unit 1 containment ADS was not formally incorporated into the dry layup program, but was included in the evaluation. The applicant stated that there were no moisture controls for the portions of the Unit 1 containment ADS within the scope of license renewal.

The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004, submittal provides the AMR of the containment ADS components within the scope of license renewal which were not incorporated into the BFN dry layup program. The component types include bolting, fittings, flex hose, heat exchangers, piping, tanks, tubing, and valves.

The LRA and the February 19, 2004, submittal identified air/gas as the internal environment of the system, whereas the external environment was inside air, outside air, buried, and embedded/encased.

For the Unit 1 containment ADS components, the applicant identified the following materials, environments, and AERMs, where, because of the uncontrolled moist air, aging effects in addition to those requiring management during the period of extended operation were identified: carbon and low-alloy steel components in air/gas (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion. Carbon low-alloy steel components in inside air (external) and outside air (external) environments are subject to loss of material due to general corrosion. Stainless steel components in air/gas (internal) environments are subject to loss of material due to crevice and pitting corrosion. Stainless steel components in buried (external) environments are subject to loss of material due to crevice and pitting corrosion, and MIC. Copper alloy components in air/gas (internal) environments are subject to loss of material due to selective leaching, crevice corrosion, pitting corrosion, and galvanic corrosion. Aluminum alloy components in air/gas environments are subject to loss of material due to crevice, pitting, and galvanic corrosion, and crack initiation/growth due to SCC. Cast iron and cast iron alloy components in air/gas (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion, as well as selective leaching. Cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the containment ADS during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 containment ADS during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the containment atmosphere dilution system.

- One-Time Inspection Program (B.2.1.29).
- Buried Piping and Tanks Inspection Program (B.2.1.31)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7, 3.0.3.1.9, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the containment ADS (84), the applicant stated that inspections will be performed prior to Unit 1 restart for certain components where additional aging effects were identified for the extended outage. These additional aging effects include those identified for carbon and low-alloy steel, stainless steel, copper alloy, aluminum alloy, and cast iron and cast iron alloy components in system locations where condensation could build up. No descriptions of the inspections were provided. In RAI 3.0-7 LP, the staff requested the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.7.3.3.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 containment ADS components not incorporated in the dry layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 containment ADS components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.4 Auxiliary Systems

3.7.4.1 Auxiliary Systems in Dry Layup

3.7.4.1.1 Standby Liquid Control System

Technical Staff Evaluation. The technical staff reviewed the AMR of the standby liquid control system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The standby liquid control system is described in LRA Section 2.3.3.18. LRA Table 3.3.2.18 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that the Unit 1 standby liquid control system was maintained in dry layup during the extended shutdown. The applicant's February 19, 2004, submittal of additional information describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

During its review, the staff determined that additional information was needed to complete its review. General RAIs 3.0-2 LP, 3.0-8 LP, and 3.0-10 LP are related to the standby liquid control system. These RAIs, the applicant's responses, and the staff's review of the applicant's responses are discussed in SER Section 3.7.1.3. There are no system-specific RAIs on the standby liquid control system.

Aging Effects. LRA Table 3.3.2.18 provides the AMR of the standby liquid control system components within the scope of license renewal and subject to AMR. The component types include piping, fittings, bolting, pumps, tanks, and valves.

The LRA and the February 19, 2004, submittal of additional information describe the environment during the Unit 1 shutdown as follows: the internal environment was maintained at less of 60 percent relative humidity (de-humidified air) and the external environment was inside air.

For the Unit 1 system components, the applicant identified on Evaluation of the Unit 1 Layup and Preservation Program Table 1, the following materials, environments, and AERMs: carbon and low-alloy steel components exposed to air/gas and inside air are subject to a loss of material due to general corrosion. Stainless steel, aluminum alloy and polymer-delrin exposed to air/gas and inside air experience no aging effects.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the standby liquid control system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 standby liquid control system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Evaluation of the Unit Layup and Preservation Program Table 1 identifies the following AMPs for managing the aging effects described above for the standby liquid control system in dry layup.

- One-Time Inspection Program (B.2.1.29)
- Systems Monitoring Program (B.2.1.39)

The staff's detailed review of these AMPs is found in SER Section 3.0.3.1.7 and 3.0.3.3.1, respectively.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 18 and 27, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 standby liquid control system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 standby liquid control system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.4.1.2 Off-Gas System

Technical Staff Evaluation. The technical staff reviewed the AMR of the off-gas system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The off-gas system is described in LRA Section 2.3.3.19. LRA Table 3.3.2.19 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that the Unit 1 off-gas system was maintained in dry layup during the extended shutdown. The applicant's February 19, 2004, submittal of additional information describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

During its review, the staff determined that additional information was needed to complete its review. General RAIs 3.0-2 LP, 3.0-8 LP, and 3.0-10 LP are related to the off-gas system. These RAIs, the applicant's response and the staff's review of the applicant's response are discussed in SER Section. There are no system-specific RAIs on the off-gas system.

Aging Effects. LRA Table 3.3.2.19 provides the AMR of the off-gas system components within the scope of license renewal and subject to AMR. The component types include bolting, ductwork, piping and fittings.

The LRA and the February 19, 2004, submittal of additional information describe the environment during the Unit 1 shutdown as follows: the internal environment was maintained at less than 60 percent relative humidity (de-humidified air), and the outside environment was inside air.

For the Unit 1 system components, the applicant identified on Evaluation of the Unit 1 Layup and Preservation Program Table 1, the following materials, environments, and AERMs: carbon and low-alloy steel components exposed to air/gas and inside air are subject to a loss of material due to general corrosion. Stainless steel and copper alloy exposed to air/gas and inside air experience no aging effects.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the off-gas system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 off-gas system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Evaluation of the BFN Unit Layup and Preservation Program Table 1 identifies the following AMPs for managing the aging effects described above for the off-gas system in dry layup.

- One-Time Inspection Program (B.2.1.29)
- Systems Monitoring Program (B.2.1.39)

The staff's detailed review of these AMPs is found in SER Section 3.0.3.1.7 and 3.0.3.3.1, respectively.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 18 and 27, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 off-gas system. components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 off-gas system. components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.4.1.3 Reactor Core Isolation Cooling System

Technical Staff Evaluation. The technical staff reviewed the AMR of the RCIC system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The reactor core isolation cooling system is described in LRA Section 2.3.3.23. LRA Table 3.3.2.23 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that Unit 1 reactor core isolation cooling system for wet layup was not formally incorporated into the wet layup program, but was evaluated. The applicant's February 19, 2004, submittal of additional information (including Table 1 and 3). shows that the RCIC system was subject to both a dry layup condition and a wetted condition. The applicant's response to RAI 3.0-6 LP shows that the RCIC torus attached piping saw torus water maintained by Chemistry Program CI-13.1 for extended periods of time. The BFN layup program for dry layup maintained the internal environment of Unit 1 reactor core isolation cooling system at less than 60 percent RH de-humidified air. The applicant's February 19, 2004, submittal of additional information (including Table 1 and 3), describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

During its review, the staff determined that additional information was needed to complete its review. General RAIs 3.0-2 LP, 3.0-3 LP, 3.0-4 LP, 3.0-5 LP, 3.0-6 LP, 3.0-8 LP, 3.0-9 LP and 3.0-10 LP are related to the reactor core isolation cooling system. RAIs 3.0-2 LP to RAI 3.0-8

LP are discussed in SER Section 3.7.1.3, RAI 3.0-9 LP is discussed in SER Section 3.7.1.2 and RAI 3.0-10 LP is discussed in SER Section 3.7.1.3. There are no system-specific RAIs on the reactor core isolation cooling system.

Aging Effects. LRA Table 3.3.2.23 provides the AMR of the reactor core isolation cooling system components within the scope of license renewal and subject to AMR. The component types include bolting, condenser, expansion joint, fittings, fittings - RCPB, flexible connector, heat exchangers, piping, piping - RCPB, pumps, restricting orifice, restricting orifice - RCPB, strainers, tanks, traps, tubing, turbines, valves, and valves - RCPB.

Table 1 of the February 19, 2004, submittal of additional information describes the dry layup environment during the Unit 1 shutdown as follows: the internal environment was air/gas (less than 60 percent RH) and the external environment was inside air. Table 3 of the February 19, 2004, submittal identifies the internal environment as treated water and the external environment as inside air or treated water.

For the Unit 1 system components, the applicant identified on Evaluation of the BFN Unit 1 Layup and Preservation Program Tables 1 and 3, the following materials, environments, and AERMs: carbon and low-alloy steel components as well as cast iron and cast iron alloy components. exposed to air/gas (internal) or inside air (external) environments are subject to a loss of material due to general corrosion; carbon and low-alloy steel components as well as cast iron and cast iron alloy components exposed to treated water are subject to general corrosion, crevice corrosion, galvanic corrosion, and pitting corrosion; stainless steel components in treated water are subject to crevice corrosion, and pitting corrosion; copper-alloy components in treated water are subject to a loss of material due to selective leaching, crevice corrosion, galvanic corrosion, and pitting corrosion; aluminum alloy components. in treated water are subject to a loss of material due to crack initiation and growth due to SCC, crevice corrosion, galvanic corrosion, and pitting corrosion; stainless steel, copper alloy, aluminum alloy, and glass components exposed to air/gas (internal) or inside air (external) environments experience no aging effects. Glass components in treated-water environment also experience no aging effects.

In response to general RAI 3.0-9 LP, the applicant identified that the RCIC steam trap drain was replaced with 2-¼ percent chromium materials to prevent FAC.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18, and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the reactor core isolation cooling system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 reactor core isolation cooling system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Evaluation of the BFN Unit Layup and Preservation Program Tables 1 and 3 identify the following AMPs for managing the aging effects described above for the reactor core isolation cooling system in a dry layup or a treated-water environment.

- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program (B.2.1.4)
- BWR Stress Corrosion Cracking Program (B.2.1.10)
- Chemistry Control Program (B.2.1.5)
- Flow-Accelerated Corrosion Program (B.2.1.15)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

The staff's detailed review of these AMPs is found in SER Section 3.0.3.1.3, 3.0.3.2.5, 3.0.3.2.2, 3.0.3.2.9, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively.

In follow-up RAI 3.3-2, the staff questioned if one-time inspections are appropriate where there may be insufficient operating experience. By letter dated May 27, 2005, the applicant clarified the application of periodic inspections in lieu of one-time inspections for areas subject to concentration of contaminants during layup. Targeted periodic inspections are going to be used as compensatory actions to be performed after Unit 1 is returned to operation to verify no additional aging effects are occurring. By letter dated November 16, 2005, the applicant also clarified that the compensatory actions included visual and/or ultrasonic inspections to establish the physical condition of systems and components not being replaced. The first periodic inspection will be performed prior to the end of the current operating period and the subsequent frequency will be determined based on the outcome of the first periodic inspections performed.

The restart inspections can be utilized as a baseline for comparison as identified in the Unit 1 Periodic Inspection Program (SER Section 3.0.3.3.5). Systems and portions of systems for which periodic inspections will be performed included MS, FW, RHRSW, RCW, EECW, fire protection, reactor building closed cooling water, RCIC, HPCI, RHR, and CRD. The staff concurred that application of targeted periodic internal visual and ultrasonic inspections of a sample of susceptible locations is appropriate to manage potential latent aging effects in Unit 1 systems and portions of systems in layup that were not in operation during the extended outage and have not been replaced.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19, 2004, October 8, 2004, and January 31, 2005, the staff found that the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 RCIC system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 reactor core isolation cooling system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.4.2 Auxiliary Systems in Wet Lay up

3.7.4.2.1 Reactor Water Cleanup System

Technical Staff Evaluation. The technical staff reviewed the AMR of the reactor water cleanup system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The reactor water cleanup system is described in LRA Section 2.3.3.21. LRA Table 3.3.2.21 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that Unit 1 reactor water cleanup system was maintained in wet lay up during the extended shutdown. The applicant's February 19, 2004, submittal of additional information, describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

During its review, the staff determined that additional information was needed to complete its review. General RAIs applicable to the RWCU system include RAI 3.0-1 LP, 3,0-3 LP, 3.0-5 LP, 3.0-7 LP, 3.0-8 LP, 3.0-9 LP, 3.0-10 LP, 3.0-11 LP. The description of these general RAIs, the applicant's response to these RAIs and the staff's review of the applicant's responses are included in SER Sections 3.7.1.1, 3.7.1.4, 3.7.1.3, 3.7.1.2, and 3.7.1.5. There are no system-specific RAIs for the reactor water cleanup system.

Aging Effects. LRA Table 3.3.2.21 provides the AMR of the reactor water cleanup system components within the scope of license renewal and subject to AMR. The component types include piping and fittings, heat exchangers, pumps, restricting orifices, strainers, tanks, tubing, and valves.

The LRA and the February 19, 2004, submittal of additional information, describe the environment during the Unit 1 shutdown as follows: the internal environment was flowing, air-saturated, demineralized water (treated water) and the outside environment was inside air.

For the Unit 1 system components, the applicant identified on Evaluation of the BFN Unit 1 Layup and Preservation Program Table 2, the following materials, environments, and AERMs: carbon and low-alloy steel components exposed to treated water are subject to a loss of material due to general corrosion, crevice corrosion, galvanic corrosion, and pitting corrosion; stainless steel components in treated water are subject to a loss of material due to crevice and pitting corrosion; cast iron and cast iron alloy components in treated water are subject to a loss of material due to general corrosion, crevice corrosion, galvanic corrosion, and pitting corrosion as well as selective leaching; copper and copper-alloy components in a treated-water environment are subject to a loss of material due to crevice corrosion, pitting corrosion and selective leaching. Glass components in a treated-water environment experience no aging effects; carbon and low-alloy steel components as well as cast iron and cast iron alloy components in inside air are subject to a loss of material due to general corrosion; stainless steel, copper alloy, and glass exposed to inside air experience no aging effects.

Table 2 does not identify IGSCC for the stainless steel RWCU system components during layup and LRA Section F.13 indicates that RWCU piping outside the primary containment isolation valves will be replaced with IGSCC-resistant material. In response to general RAI 3.0-9 LP the applicant submitted system-specific information in regard to specific components that will be replaced prior to startup. By letter dated January 31,2005, the applicant clarified the scope and basis for the following RWCU specific components being replaced with IGSCC-resistant material prior to Unit 1 restart:

- RWCU hot piping both inside and outside the drywell is being replaced with 316NG
- RWCU valves replaced with 316L
- RWCU pumps (IGSCC related)
- RWCU regenerative heat exchangers with 316L

Therefore, based on the commitment that stainless steel piping will be replaced with IGSCC-resistant material prior to Unit 1 restart, the staff concluded that IGSCC is not a technical concern for the RWCU system as a result of layup conditions during the extended shutdown.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the reactor water cleanup system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 reactor water cleanup system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Evaluation of the BFN Unit Layup and Preservation Program Table 2 identified the following AMPs for managing the aging effects described above for the reactor water cleanup system in wet layup.

- ASME Section XI Subsections IWB, IWC and IWD Inspection Program (B.2.1.4)
- Bolting Integrity Program (B.2.1.16)
- BWR Reactor Water Cleanup System Program (B.2.1.22)
- Chemistry Control Program (B.2.1.5)
- Closed-Cycle Cooling Water System Program (B.2.1.18)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

The staff's detailed review of these AMPs is found in SER Sections 3.0.3.1.3, 3.0.3.2.10, 3.0.3.2.15, 3.0.3.2.2 3.0.3.2.12, 3.0.3.1.7, 3.0.3.1.8X, and 3.0.3.3.1, respectively.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19, 2004, October 8, 2004, and January 31, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 reactor water cleanup system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 reactor water cleanup system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.4.2.2 Control Rod Drive System

Technical Staff Evaluation. The technical staff reviewed the AMR of the CRD system to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The CRD system is described in LRA Section 2.3.3.29. LRA Table 3.3.2.29 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that the Unit 1 CRD system was maintained in wet layup during the extended shutdown. The applicant's February 19, 2004, submittal (including Table 2) describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

During its review, the staff determined that additional information was needed to complete its review. General RAIs 3.0-1 LP, 3.0-3 LP, 3.0-5 LP, 3.0-6 LP, 3.0-9 LP, and 3.0-10 LP are related to the CRD system. The description of the general RAIs that relates to both the SSCs in the auxiliary system and other mechanical system groups, the applicant's response to these RAIs and the staff's review of the applicant's responses are in SER Sections 3.7.1.1, 3.7.1.4, 3.7.1.3, and 3.7.1.2. System-specific RAI 3.3-2 LP on the CRD system, the applicant's responses and the staff's review of the applicant's responses are described below.

Aging Effects. LRA Table 3.3.2.29 provides the AMR of the CRD system components within the scope of license renewal and subject to AMR. The component types include bolting, fittings, fittings - RCPB, heat exchangers, piping, piping - RCPB, pumps, restricting orifice, rupture disk, strainers, strainers - RCPB, tanks, tubing, valves, and valves - RCPB.

Table 2 of the February 19, 2004, submittal describes the environment during the Unit 1 shutdown as follows: the internal environment was flowing, air-saturated, demineralized water (treated water) and the outside environment was inside air.

For the Unit 1 system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components exposed to air-saturated demineralized water are subject to a loss of material due to general corrosion, crevice corrosion, galvanic corrosion, and pitting corrosion; stainless steel and aluminum alloy components in treated water are subject to a loss of material due to crevice and pitting corrosion; carbon and low-alloy steel components as well as cast iron and cast iron alloy components in inside air are subject to a loss of material due to general corrosion; stainless steel, copper alloy, and aluminum alloy components exposed to inside air experience no aging effects.

In RAI 3.3-2 LP the staff requested the following additional information on Table 2 concerning the internal environment and inspections for the CRD system.

LRA Table 3.3.2.29 and Table 2 of the supplement state that many carbon and low-alloy steel components in the CRD system have an internal environment of raw water during normal operation. However, Table 2 states that this environment is not applicable during the extended outage. The applicant was requested to clarify the environment during the extended outage, and discuss the implications of the environment on the aging of these components. The applicant was requested to specify any applicable aging effects with the corresponding AMPs and also discuss whether any inspections are planned to determine the extent of aging during the extended outage.

The applicant responded to RAI 3.3-2 LP (b)1 by stating that the raw cooling water system provides cooling water to the CRD pump oil cooler and thrust bearing. The applicant further clarified that the following materials see the raw water environment during layup: carbon steel piping and fittings, copper valves, copper heat exchanger (cooler) tubing, cast iron heat exchanger (cooler) head.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18, and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the CRD system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the unit CRD system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Evaluation of the BFN Unit Layup and Preservation Program Table 3 identifies the following AMPs for managing the aging effects described above for the CRD system in wet layup:

- BWR Stress Corrosion Cracking Program (B.2.1.10)
- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29)
- Open-Cycle Cooling Water System Program (B.2.1.17)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

The staff's detailed review of these AMPs is found in SER Section 3.0.3.2.5, 3.0.3.2.2, 3.0.3.1.7, 3.0.3.2.11, 3.0.3.1.8, and 3.0.3.3.1, respectively.

In response to RAI 3.3-2 LP, the applicant stated that a sample of components with a raw water environment within the CRD system (85) will be inspected for the following aging effects by the One-Time Inspection Program.

- Carbon and low-alloy steel – Loss of material due to general corrosion, crevice corrosion, pitting corrosion, galvanic corrosion, microbiologically influenced corrosion, and biofouling
- Copper and copper alloys – Loss of material due to crevice corrosion, pitting corrosion, microbiologically influenced corrosion, biofouling, and selective leaching
- Cast iron and cast iron alloys - Loss of material due to general corrosion, crevice corrosion, pitting corrosion, galvanic corrosion, microbiologically influenced corrosion, biofouling, and selective leaching

The staff reviewed the applicant's above response to the RAI and determined that additional information was required. In follow-up RAI 3.3-2 LP the applicant was requested to clarify whether one-time inspection is appropriate to manage aging of carbon steel, cast iron and copper-based components in a raw water environment during layup.

The applicant's response to follow-up RAI 3.3-2 LP stated that there is no need to perform a one-time inspection on the components that were subjected to a raw water environment during layup. The applicant indicated that the inspections would have been better characterized as "restart inspection" instead of "One-Time Inspection." The applicant further stated that once the CRD system is returned to service the components will have the same AMPs applied to them as their current Unit 2 and 3 counterpart components.

Staff reviewed the applicant's response and concurred that, in general, restart inspections are appropriate to detect and correct degradation experienced during layup. However, staff is concerned that one-time inspections performed during the extended outage may not be appropriate to detect latent aging effects in the CRD system resulting from layup during the extended operating period. Latent aging effects are anticipated in crevices and in stagnant areas where contaminants are concentrated. For areas subject to concentration of contaminants during layup, the applicant should justify the application of one-time inspections in lieu of periodic inspections. By letter dated May 27, 2005, the applicant clarified the application of periodic inspections in lieu of one-time inspections for areas subject to concentration of contaminants during layup. Targeted periodic inspections are going to be used as compensatory actions to be performed after Unit 1 is returned to operation to verify no additional aging effects are occurring. By letter dated November 16, 2005, the applicant also clarified that the compensatory actions included visual and/or ultrasonic inspections to establish the physical condition of systems and components not being replaced. The first periodic inspection will be performed prior to the end of the current operating period and the subsequent frequency will be determined based on the outcome of the first periodic inspections performed.

The restart inspections can be utilized as a baseline for comparison as identified in the Unit 1 Periodic Inspection Program (SER Section 3.0.3.3.5). Systems and portions of systems for which periodic inspections will be performed included MS, FW, RHRSW, RCW, EECW, fire protection, reactor building closed cooling water, RCIC, HPCI, RHR, and CRD. The staff concurred that application of targeted periodic internal visual and ultrasonic inspections of a sample of susceptible locations is appropriate to manage potential latent aging effects in Unit 1 systems and portions of systems in layup that were not in operation during the extended outage and have not been replaced.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 CRD system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects [pending resolution of the general RAIs] for the Unit 1 CRD system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.4.3 Auxiliary Systems Not in Layup Program

During its review of auxiliary systems, the staff determined that additional information was needed to complete its review. By letter dated August 23, 2004, the staff issued general RAI 3.3-1 LP requesting the following additional information on systems and portions of systems that were not included in the layup program.

> LRA Section 3.0.1 describes the criteria for evaluating systems for aging during the extended outage. Systems that remain in operation for Unit 1 or in support of operation for Units 2 and 3 are not evaluated. However, based on the system descriptions, it appears that at least a portion of the following systems should have been evaluated (i.e., it appears that the system was idle or that only the main headers were needed to support operation of Units 2 and 3). Discuss the operation of the following systems during the extended shutdown, and explain why these systems were not evaluated for aging during the extended shutdown.
>
> - Residual Heat Removal Service Water System (023)
> - Control Air System (032)
> - Sampling and Water Quality System (043)
> - Emergency Equipment Cooling Water System (067)
> - Reactor Water Cleanup System (069)
> - Reactor Building Closed Cooling Water System (070)

- Radioactive Waste Treatment System (077)
- Neutron Monitoring System (092)

If it is determined that these systems, or portions thereof, met the criteria for evaluation, provide an evaluation of aging during the extended outage. Include a description of the environment, identification of AERMs, and proposed aging management. Also, discuss any inspections that are planned to determine the extent of aging during the extended outage.

By letter dated October 8, 2004, the applicant responded to RAI 3.3-1 LP by providing the following additional information.

With regard to residual heat removal service water system (23) and emergency equipment cooling water system (67), the applicant stated that the Unit 1 portions of piping and components for these systems not required for Unit 2 and 3 operation are not in the layup program. The piping and components in these systems are in shared systems and contained either raw water or moist air during the extended outage period. The applicant stated that these systems have been evaluated for a raw water and/or moist air environment for the in-service portions of these systems. The aging effects identified for the operating conditions encompass the aging effects for the layup conditions. The restart inspection will be performed prior to Unit 1 restart to verify the material condition.

The applicant also stated that for control air system (32) the Unit 1 piping components of this system not required for Unit 2 and 3 operation but in scope for license renewal is not in the layup program. For this system, any additional aging effects would be due to moisture collecting in the system components. For the operating condition the internal environment is air/gas without a significant amount of moisture present. During layup there were no moisture controls on the non-operating Unit 1 portions of this system. Without moisture controls the possibility of moisture collecting at system low points exists. The aging effects associated with moist air are contained in the detailed layup evaluation of the containment inerting system (76) and the containment atmosphere dilution system (84). The potential aging effects for the control air will be similar to those identified for the containment inerting and containment atmosphere dilution systems. The restart inspection will be performed prior to Unit 1 restart to verify the material condition.

For the sampling and water quality system (43), the applicant stated that the Unit 1 piping and components of this system not required for Unit 2 and 3 operation are not in the lay-up program. The piping and components in this system contained treated water, raw water, and/or moist air during the extended outage period. This system has been evaluated for these environments for the operating condition. The aging effects identified for the operating conditions encompass the aging effects for the layup conditions. The restart inspection will be performed prior to Unit 1 restart to verify the material condition. Related to the reactor water cleanup system (69), the applicant stated that the system was evaluated per BFN Unit 1, Layup and Preservation Program, Table 2.

For the reactor building closed cooling water system (70) the applicant stated that portions of the Unit 1 piping and components of this system not required for Unit 2 and 3 operation are not in the layup program. The piping and components in this system contained treated water maintained to CI-13.1 and/or moist air during the extended outage period. The aging effects associated with treated water maintained to CI-13.1 are contained in the detailed layup evaluation of the reactor core isolation cooling system (71), the HPCI system (73), and the core spray system (75). The potential aging effects for the closed cooling water system (70) will be similar to those identified for the reactor core isolation cooling system (71), the HPCI system (73), and the core spray system (75). The restart inspection will be performed prior to Unit 1 restart to verify the material condition.

For the radioactive waste treatment system (77), the applicant stated that the Unit 1 piping and components for this system are not in the layup program. The piping and components in this system within the LRA scope remained in-service. An aging effects evaluation was performed for this system and documented in LRA Table 3.3.2.25.

Finally, related to the neutron monitoring system (92), the applicant stated that the Unit 1 portions of piping and components for this system are not in the layup program. The portion of this system that is within the scope of license renewal is part of the reactor vessel pressure boundary. An aging effects evaluation was performed for the Unit 1 layup portions of the RVI system. The aging effects evaluation for the RV and RVI encompasses the neutron monitoring system (92). The restart inspection will be performed prior to Unit 1 restart to verify the material condition.

With the staff issue raised in RAI 3.0-3 LP concerning MIC in stagnant areas, the staff reviewed the applicant's response to RAI 3.0-3 and, in general, found it to be reasonable and acceptable because it clarified that the subject systems were either in-service or were not part of the layup program. Systems that were in service during the extended outage are reviewed as part of the AMR. For systems that were not part of the layup program, the applicant includes an evaluation of aging effects and credits restart inspections to verify the material condition. In these systems, the applicant's evaluation of aging effects determined that aging effects identified for the operating conditions encompass the aging effects for the layup conditions. The staff's evaluation of restart inspections to manage aging effects including MIC for stagnant systems not in-service can be found in SER Sections 3.0.3.3.5, 3.7.1.3, and 3.7.1.4.

3.7.5 Steam and Power Conversion Systems

3.7.5.1 Steam and Power Conversion Systems in Wet Layup

3.7.5.1.1 Feedwater System

Technical Staff Evaluation. The technical staff reviewed the AMR of the feedwater system (03) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The feedwater system is described in LRA Section 2.3.4.3. LRA Table 3.4.2.3 contains the AMR for the system for normal operation. LRA Section 3.0.1 states that Unit 1 feedwater system was maintained in wet layup during the extended shutdown. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 2 of the applicant's February 19, 2004, submittal provides the AMR of the feedwater system components within the scope of license renewal that were maintained in wet layup conditions. The component types include bolting, fittings, piping, restricting orifices, tubing, and valves.

The February 19, 2004, submittal states that portions of the Unit 1 feedwater system are within the boundary of the layup program. However, the portions of the Unit 1 feedwater system within the scope of license renewal sees the same water as the portions of Unit 1 reactor vessel and internals system, boiler drains and vents system, recirculation system, reactor water cleanup system, and CRD system. The applicant stated that BFN maintains the internal environment of these systems with flowing, air-saturated, demineralized water per the CI-13.1 chemistry program. Due to drainage and system isolation, portions of these systems did not see the same environment as that seen by the portions of the Unit 1 feedwater system within the scope of license renewal, for an extended period of time. The applicant stated, however, that the evaluation for treated water encompasses the aging effects for a moist air environment in these systems.

For the Unit 1 feedwater system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion; carbon and low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion; stainless steel components in treated water (internal) environments are subject to loss of material due to crevice and pitting corrosion; copper-alloy components in air/gas (internal) moist environments are subject to loss of material due to crevice, galvanic, and pitting corrosion, as well as selective leaching; no AERMS were identified for stainless steel and copper-alloy components in inside air (external) environments.

On the basis of its review of the information provided in the LRA, as supplemented by letter dated February 19, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the feedwater system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 feedwater system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 2 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the feedwater system.

- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program (B.2.1.4)
- Chemistry Control Program (B.2.1.5)
- Flow-Accelerated Corrosion Program (B.2.1.15)
- One-Time Inspection Program (B.2.1.29)

SER Sections 3.0.3.1.3, 3.0.3.2.2, 3.0.3.2.9, and 3.0.3.1.7, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 2 of the February 19, 2004, submittal, for the feedwater system (03), the applicant indicated that carbon and low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion, because the components' surface temperature is less than 212°F during the period of extended outage. The applicant indicated that the components will be inspected for external corrosion prior to Unit 1 restart, without providing details for the inspection provided. The applicant also indicated that inspections will be performed prior to Unit 1 restart for the copper-alloy components for which additional aging effects (i.e., loss of material due to crevice, galvanic, and pitting corrosion, and selective leaching) were identified for the extended outage. These additional aging effects are the results of the presence of moist air in system locations where condensation could build up. The applicant indicated that inspections will be performed for the components prior to Unit 1 restart, but again, provided no descriptions of the inspections.

In RAI 3.0-7 LP, the staff requested the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections. By letter dated October 8, 2004, the applicant stated that external surface monitoring will be performed for the affected carbon and low-alloy steel components in accordance with the Systems Monitoring Program described in LRA, Appendix B, LRA Section B.2.1.39. The applicant noted that this is the same AMP proposed for managing external loss of material during the period of extended operation. By letters dated January 31 and May 18, 2005, and January 31, 2006, the applicant stated that restart inspections of the internal surface will be performed prior to Unit 1 restart to verify the material condition for the affected copper-alloy components. The applicant also committed to perform the Unit 1 Periodic Inspection Program for specific locations of piping and fitting components before and during the period of extended operation. The staff determined the Systems Monitoring Program to be adequate in managing the external aging effects. The staff also determined that the applicant's commitment of performing restart inspections, followed by periodic inspections, for the internal aging effects is acceptable. RAI 3.0-7 LP is, therefore, closed for the feedwater system. The staff's discussion of the general adequacy of restart inspections managing the aging effects versus periodic inspections during the period of extended outage is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 feedwater system components during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 feedwater system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.5.2 Steam and Power Conversion Systems in Various Wet Environments

3.7.5.2.1 Condenser Circulation Water System

Technical Staff Evaluation. The technical staff reviewed the AMR of the condenser circulation water system (27) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The condenser circulation water system is described in LRA Section 2.3.4.6. LRA Table 3.4.2.6 provides the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that the portion of Unit 1 condenser circulation water system within the scope of license renewal was not incorporated into the wet layup program, but was included in the evaluation. Based, in part, on location and valve leakage, the components within the scope of license renewal for the condenser circulation water system (27) experienced raw stagnant water for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 3 of the February 19, 2004, submittal provides the AMR of the condenser circulation water system components within the scope of license renewal thath were not incorporated into the wet layup program. The component types include bolting, fittings, piping, strainers, tubing, and valves.

The February 19, 2004, submittal identified raw water as the internal environment of the system, and the external environment was inside air, outside air, buried, and embedded/encased.

For the Unit 1 condenser circulation water system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in raw water (internal) environments are subject to loss of material due to general, crevice, and pitting corrosion, as well as loss of material due to biofouling and MIC; carbon and low-alloy steel components in inside air (external) and outside air (external) environments are subject to loss of material due to general corrosion; carbon and low-alloy steel components in buried (external) environments are subject to loss of material due to general, crevice, and pitting corrosion, as well as MIC; cast iron and cast iron alloy components in raw water (internal) environments are subject to loss of material due to general, crevice, and pitting corrosion, as well as loss of material due to biofouling and MIC; cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion; no aging effects are identified for carbon and low-alloy steel components in embedded/encased (external) environments, and stainless steel and copper-alloy components in inside air (external) environments.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of its February 19, 2004, submittal, the applicant stated that, for the condenser circulation water system (27), carbon and low-alloy steel components and cast iron and cast iron alloy components in raw water (internal) environments were susceptible to loss of material. due to general, crevice, and pitting corrosion, as well as loss of material due to biofouling and MIC. Since the components were exposed to raw stagnant water for an extended period of time, portions of the components, especially those at low points, may have already been subject to aging degradation far more severe than their Units 2 and 3 counterparts in normal plant operation. In RAI 3.4-2 LP, the staff requested the applicant to justify the basis for not performing inspections for the aging effects prior to Unit 1 restart. By letter dated October 8, 2004, the applicant stated that during normal operation and layup, condenser circulation water system components saw raw stagnant water. Restart inspections will be performed prior to Unit 1 restart to verify the material condition. The staff determined that the applicant's commitment of performing restart inspections prior to Unit 1 restart is acceptable, and RAI 3.4-2 LP is closed. The staff's discussion of the general adequacy of the applicant's restart inspections for systems containing raw water during layup is provided in SER Section 3.7.1.

In Table 3 of its February 19, 2004, submittal, the applicant stated that, for condenser circulation water system (27), cast iron and cast iron alloy components (valves, fittings, etc.) were exposed to raw water (internal) environments, and identified no aging effects due to selective leaching. The staff noted that in raw water environments, leaching in the form of graphitic corrosion could occur with loss of iron matrix from gray cast iron. In addition, gray cast iron can also display the effects of selective leaching in relatively mild environments. In RAI 3.4-3 LP, the staff requested the applicant to discuss why selective leaching is not identified as a potential aging mechanism requiring management for the components. By letter dated October 8, 2004, the applicant stated that the aging effects write-up in its February 19, 2004, submittal did identify selective leaching as an aging mechanism for gray cast iron for the condenser circulation water system, and the line item in Table 3 should have included selective leaching for gray cast iron in the system. This response is acceptable to the staff, and RAI 3.4-3 LP is closed.

In Table 3 of the applicant's February 19, 2004, submittal, the applicant indicates that components in the condenser circulation water system (27) and gland seal water system (37) are exposed to an air/gas internal environment during normal operation, whereas the environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of these systems saw a moist air environment for extended periods of time. The table states, however, that the evaluation for raw and treated water encompasses the aging effects for a moist air environment in these systems. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the raw and treated-water environment would encompass that of the aging effects for a moist air environment in these systems, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing raw or treated-water environment during normal operation. By letter dated October 8, 2004, the applicant stated that Table 3 addresses the aging management for portions of several systems (including condenser circulation water and gland seal water systems) laid up in a wet environment. Due to closure sequence, closure timing, and possible leakage past the double isolation valves or two drain valves for these systems, it is assumed that an air/gas environment with an uncertain amount of moisture was trapped between the double isolation valves. The trapped moisture between the double isolation valves was considered the same (i.e., raw or treated water) as was flowing through the valves prior to closure. The applicant stated that the N/A (not applicable) denotes that this trapped air/gas environment will be evaluated under the corresponding raw or treated water evaluations.

The applicant stated that the evaluation of these moist air environments for the systems addressed in Table 3 identified no additional aging effects other than those identified for the corresponding raw or treated-water environment. The applicant stated that the LRA identified these trapped air environments for one-time inspections because the extent of corrosion could be quantified. It was not the intent of this AMR to determine the rate of loss of material. The applicant further stated that the restart inspection will be performed prior to Unit 1 restart to verify the material condition.

The staff determined that the applicant had adequately explained the nature of the trapped air/gas environments, and why the evaluation of the aging effects for the raw and treated-water environments, in the above two systems, would encompass that of the aging effects for a moist air environment in these systems. The applicant also committed to perform restart inspections prior to Unit 1 restart, to verify the material condition of the system components. This is acceptable to the staff, and RAI 3.0-5 LP is closed for the condenser circulation water system (27) and gland seal water system (37) systems. The staff's discussion of the general adequacy of the restart inspections for systems containing treated water and raw water during layup is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the condenser circulation water system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 condenser circulation water system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 identifies the following AMPs for managing the aging effects described above for the condenser circulating water system.

- One-Time Inspection Program (B.2.1.29)
- Buried Piping and Tanks Inspection Program (B.2.1.31)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.7, 3.0.3.1.9, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of its February 19, 2004, submittal, the applicant identified no additional AMPs for the components in this layup system, other than the above AMPs specified in the LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the conclusion by discussing the water samples performed for the normal operation and the period of extended outage. By letter dated October 8, 2004, the applicant stated that the condenser circulation water system was exposed to Tennessee River water, which is the same environment it is exposed to during normal operation. Without the addition of foreign chemicals, the aging effects during normal operation and during layup are the same. However, the applicant stated that the restart inspection will be performed prior to Unit 1 restart to verify the material condition. This commitment is acceptable to the staff, and RAI 3.0-6 LP is closed for the condenser circulation water system. The staff's discussion of the general adequacy of the restart inspections as it relates to the systems containing raw water during layup is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; January 31, and May 18 and 27, 2005; the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 condenser circulation water system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 condenser circulation water system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.5.2.2. Gland Seal Water System

Technical Staff Evaluation. The technical staff reviewed the AMR of the gland seal water system (37) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The gland seal water system is described in LRA Section 2.3.4.7. LRA Table 3.4.2.7 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that the portion of the Unit 1 gland seal water system within the scope of BFN license renewal was not incorporated into the BFN wet layup program, but was included in the evaluation. Based on location, valve leakage, etc., the components within the scope of license renewal for the gland seal water system (37) saw treated water for extended periods of time. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 3 of the February 19, 2004, submittal provides the AMR of the gland seal water system components within the scope of license renewal that were not incorporated into the BFN wet layup program. The component types include bolting, fittings, piping, tanks, tubing, and valves.

The February 19, 2004, submittal identified treated water as the internal environment of the system, and the external environment was inside air.

For the Unit 1 gland seal water system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in treated water (internal) environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion; carbon and low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion; copper-alloy components in treated water (internal) environments are subject to loss of material due to selective leaching, crevice and pitting corrosion; cast iron and cast iron alloy components in treated water (internal) environments are subject to loss of material due to general, crevice, and pitting corrosion, as well as selective leaching; cast iron and cast iron alloy components in inside air (external) environments are subject to loss of material due to general corrosion; no AERMS are identified for carbon and low-alloy steel in air/gas (internal) environments, copper alloy components in air/gas (internal) environment, and cast iron and cast iron alloy in air/gas (internal) environments no aging effects are identified for glass components in treated water (internal), air/gas (internal), and inside air (external) environments.

During its review, the staff determined that additional information was needed to complete its review.

In Table 3 of its February 19, 2004, submittal, the applicant stated that the portion of the gland seal water system (37) within the scope of license renewal was not incorporated into the Unit 1 wet layup program. The applicant identified various aging effects for carbon and low-alloy steel, copper alloy, and cast iron and cast iron alloy components in treated water (internal) environments. To ensure that these components have not been subjected to aging degradation more severe than their Units 2 and 3 counterparts during plant operation, in RAI 3.4-1 LP, the staff requested that the applicant (1) describe the general environments associated with the above system components; (2) provide a detailed description of the water chemistry of the treated water and discuss its differences from the water chemistry existing in the plant operation; (3) discuss any water chemistry monitoring that had been performed for the treated water during the layup period; (4) discuss the possibility of incurring more severe aging degradations to these layup components than could have occurred during plant operation, considering the potential effects of different water temperature and stagnant flow condition; (5) discuss how the latent effect of the potentially more severe aging degradation occurring in the Unit 1 layup can be accounted for in the license AMR; and (6) justify the basis for not performing inspections for potential aging effects for these components prior to Unit 1 restart. By letter dated October 8, 2004, the applicant provided the following information:

1. Gland seal water system was drained (ambient air present) with the gland seal tank in component layup per MPI-1-000-TNK002. However, it was assumed that the secondary containment loop seal as well as other low points in the system were not completely drained (the layup environment for the system is treated (condensate) water and moist air from possible pooling of treated water between drain or isolation valves and in the loop seals). Therefore, stagnant treated water supplied from the condensate system (02) was evaluated for these areas.
2. The impurity administrative goals for conductivity, chloride, and sulfate given in CI-13.1 are 2.0. µS/cm, 75 ppb, and 75 ppb, respectively. Sampling is performed weekly. The chemistry program implemented during the wet layup period is essentially the same program that BFN uses on the two operating units during cold shutdown conditions for refueling and maintenance outage. This extended operation program would consist of CI-13.1 "Chemistry Program" controls which would continue to be based on the EPRI BWR Water Chemistry Guidelines (TR-103515).
3. As discussed in Item (1), the treated water is sampled and monitored per the Chemistry Control Program CI-13.1. The aging effects/aging mechanisms for the components within the systems in layup are similar to those determined for the operational units.
4. As discussed in Item (1), the possibility of low flow or stagnant conditions exists in this system. Due to low flow conditions in the system, the restart inspection will be performed prior to Unit 1 restart to verify the material condition.
5. There have been no latent effects identified for the chemistry program implemented during the Unit 1 wet layup period. This program is essentially the same program that BFN uses for operating units during cold shutdown conditions for refueling and maintenance outages (EPRI BWR Water Chemistry Guidelines TR-103515-R2).
6. The restart inspection will be implemented prior to Unit 1restart.

Based on the above responses to the RAI, the staff considered that the applicant had adequately addressed its concerns, and ensured that the wet layup components in the system had not been subjected to aging degradation more severe than their Units 2 and 3 counterparts during plant operation. RAI 3.4-1 LP is, therefore, closed for the gland seal water system. The staff's discussion for the general adequacy of the One-Time Inspection Program as a verification program for layup and chemistry control is provided in SER Section 3.7.1.3.

Table 3 of the applicant's February 19, 2004, submittal indicates that components in the gland seal water system (37) are exposed to an air/gas internal environment during normal operation, whereas the environment during the extended outage is noted as "N/A." This table states that, due to drainage and system isolation, portions of this system may have been exposed to an internal environment of moist air. The table also states that the evaluation for treated water encompasses the aging effects for a moist air environment in this system. In RAI 3.0-5 LP, the staff requested the applicant to explain why the evaluation of the aging effects for the treated-water environment would encompass that of the aging effects for a moist air environment in this system, since the rate of loss of material caused by a moist air environment during layup may be more severe than a flowing treated-water environment during normal operation. The staff's discussion of this RAI and its resolution by the applicant are provided in SER Section 3.7.5.2.1.

Table 3 of the applicant's February 19, 2004, submittal indicates that, for gland seal water system (37), copper-alloy components and cast iron and cast iron alloy components saw treated (condensate) water for an extended period of time. The applicant identified loss of material due to general corrosion, selective leaching, crevice corrosion, and pitting corrosion as the AERMs. In RAI 3.4-4 LP, the staff requested the applicant to explain why galvanic corrosion is not identified as a potential aging mechanism for the components. By letter dated October 8, 2004, the applicant stated that the cast iron components within the gland seal water system (37) are in contact with carbon steel piping. Cast iron and carbon steel are grouped together in the galvanic series as similar metals. Since cast iron components within the system are not in contact with more cathodic materials, galvanic corrosion is not a concern. Similarly, copper-alloy components are not in contact with a more cathodic material such as stainless steel within the gland seal water system. Therefore, galvanic corrosion is not a concern. The staff found the applicant's explanation to be acceptable, and RAI 3.4-4 LP is closed.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004; and January 31, and May 18 and 27, 2005; the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the gland seal water system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 gland seal water system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 3 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the gland seal water system.

- Chemistry Control Program (B.2.1.5)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.2.2, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

Table 3 of the applicant's February 19, 2004, submittal indicates that components in the gland seal water system (37) were exposed to treated (non-controlled) water environments during the extended outage. Table 3 identified no additional AMPs for this layup system, other than those AMPs specified in the LRA for the period of extended operation. In RAI 3.0-6 LP, the staff requested the applicant to justify the determination by discussing the water sampling performed for the normal operation and the period of extended outage. By letter dated October 8, 2004, the applicant stated that the system had been drained (ambient air present) with gland seal tank in component layup per MPI-1-000-TNK002. However, it was assumed that the secondary containment loop seal as well as other low points in the system had not been completely drained. Therefore, stagnant treated water supplied from the condensate system (02) was evaluated for these areas. The applicant stated that a restart inspection will be performed prior to Unit 1 restart to verify the material condition. The staff found the applicant's commitment to perform a restart inspection for the potential low points in the system to be acceptable, and RAI 3.0-6 LP is closed for the gland seal water system. The staff's discussion of the general adequacy of the restart inspections in managing the identified aging effects for the system components, as opposed to periodic inspections, is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, 2005, May 18 and 27, 2005, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 gland seal water system components not incorporated in the wet layup program during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 gland seal water system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.5.3 Steam and Power Conversion Systems in Various Dry Environments

3.7.5.3.1 Main Steam System

Technical Staff Evaluation. The technical staff reviewed the AMR of the main steam system (01) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The main steam system is described in LRA Section 2.3.4.1. LRA Table 3.4.2.1 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that portions of Unit 1 main steam system are within the boundary of the BFN layup program. However, the portions of this system within the scope of license renewal are those that lack moisture controls and are considered moist air control components. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004, submittal provides the AMR of the main steam system components within the scope of license renewal that were exposed to an air environment that lacked moisture controls. The component types include bolting, fittings, piping, restricting orifices, strainers, tubing, and valves.

The applicant's February 19, 2004, submittal identified air/gas (moist air) as the internal environment of the system, whereas the external environment was inside air.

For the Unit 1 main steam system components, the applicant identified the following materials, environments, and AERMs, where, because of the uncontrolled moist air, aging effects different from those requiring management during the period of extended operation were identified: aluminum alloy components in air/gas (internal) moist air environments are subject to loss of material due to crevice, galvanic, and pitting corrosion, as well as crack initiation/growth due to SCC, carbon and low-alloy steel components in air/gas (internal) moist air environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion; carbon low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion; stainless steel components in air/gas (internal) moist air environments are subject to loss of material due to crevice corrosion and pitting corrosion; no aging effects are identified for aluminum alloy and stainless steel components in inside air (external) environments.

On the basis of its review of the information provided in the LRA, as supplemented by letter dated February 19, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the main steam system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 main steam system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the main steam system.

- ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program (B.2.1.4)
- Chemistry Control Program (B.2.1.5)
- BWR Stress Corrosion Cracking Program (B.2.1.10)
- Flow-Accelerated Corrosion Program (B.2.1.15)
- One-Time Inspection Program (B.2.1.29)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.1.3, 3.0.3.2.2, 3.0.3.2.5, 3.0.3.2.9, 3.0.3.1.7, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the main steam system (01), the applicant indicated that inspections will be performed prior to Unit 1 restart for the aluminum alloy components for which additional aging effects (i.e., loss of material due to crevice, galvanic, and pitting corrosion, and crack initiation/growth due to SCC) had been identified for the extended outage. These additional aging effects are the results of the presence of moist air in system locations where condensation could build up. The applicant indicated that inspections will be performed for the components prior to Unit 1 restart. However, no descriptions of the inspections were provided. In RAI 3.0-7 LP, the staff requested the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections. By letter dated October 8, 2004, the applicant stated that internal surface monitoring is performed in accordance with the One-Time Inspection Program described in the LRA Section B.2.1.29. The applicant noted that this is the same AMP proposed for managing internal aging effects of components exposed to moist air during the period of extended operation. By letter dated January 31, 2005, in response to RAI 3.0-10 LP, the applicant stated that the inspections described in the October 8, 2004, letter would have been better characterized as restart inspections instead of one-time inspections. Thus, the reference to the One-Time Inspection Program performed prior to restart in the October 8, 2004, letter is considered to be a restart inspection. The staff found the applicant's commitment to perform restart inspections prior to Unit 1 restart to be acceptable, and RAI 3.0-7 LP is closed for the main steam system. The staff's discussion of the general adequacy of restart inspections managing the identified aging effects versus periodic inspections during the period of extended outage is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, January 31, May 18 and 27, 2005, the staff found the applicant identified appropriate AMPs for managing the aging effects of the Unit 1 main steam system components exposed to an environment that lacked moisture controls. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 main steam system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.5.3.2 Condensate and Demineralized Water System

Technical Staff Evaluation. The technical staff reviewed the AMR of the condensate and demineralized water system (02) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The condensate and demineralized water system is described in LRA Section 2.3.4.2. LRA

Table 3.4.2.2 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal states that portions of Unit 1 condensate and demineralized water system are within the boundary of the BFN layup program. However, the portions of this system within the scope of license renewal lacked moisture controls and is, therefore, considered moist air. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004 submittal; provides the AMR of the condensate and demineralized water system components within the scope of license renewal that were exposed to an air environment that lacked moisture controls. The component types include bolting, condenser, expansion joint, fittings, piping, pumps, restricting orifices, tanks, tubing, and valves. In its submittal, the applicant. identified air/gas (moist air) as the internal environment of the system, whereas the external environment was inside air and outside air.

For the Unit 1 condensate and demineralized water system components, the applicant identified the following materials, environments, and AERMs: copper-alloy components in air/gas (internal) moist air environments are subject to loss of material due to selective leaching, crevice corrosion, and pitting corrosion; aluminum alloy components in air/gas (internal) moist air environments are subject to loss of material due to crevice, galvanic, and pitting corrosion, as well as crack initiation/growth due to SCC; carbon and low-alloy steel components in air/gas (internal) moist air environments are subject to loss of material due to general, crevice, and pitting corrosion; carbon low-alloy steel; and cast iron and cast iron alloy components in inside air (external) or outside air (external) environments are subject to loss of material due to general corrosion; stainless steel components in air/gas (internal) moist air environments are subject to loss of material due to crevice corrosion and pitting corrosion; cast iron and cast iron alloys in air/gas (internal) moist air environments are subject to loss of material due to galvanic, general, crevice, and pitting corrosion, as well as selective leaching; no aging effects are identified for Copper-alloy components in inside air (external) environments; no aging effects are identified for aluminum alloy, and stainless steel components in an inside air. (external) or outside air (external) environment; no aging effects are identified for polymer materials in an air/gas (internal) moist air or inside air (external) environment.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of its February 19, 2004, submittal, the applicant identified galvanic corrosion for the cast iron and cast iron alloys in air/gas (internal) environments during the Unit 1 layup period, but not for the plant operating condition. In RAI 3.4-5 LP, the staff requested the applicant to explain the discrepancy. By letter dated October 8, 2004, the applicant stated that the cast iron valves and fittings within the scope of license renewal for both normal operation and Unit 1 layup are coupled with either carbon steel or aluminum. Due to cast iron being either equal to or greater than carbon steel or aluminum in galvanic series, galvanic corrosion is not a concern for the cast iron components within the scope of license renewal for the condensate and demineralized water system. The staff found the applicant's explanation to be acceptable, and RAI 3.4-5 LP is closed.

In RAI 3.4-6 LP, the staff requested the applicant to explain why galvanic corrosion was not identified as a potential aging mechanism for the copper-alloy components in the condensate and demineralized water system that are exposed to air/gas (internal) moist air environments. By letter dated October 8, 2004, the applicant stated that the copper-alloy fittings and valves within the scope of license renewal for the condensate and demineralized water system are not in contact with a more cathodic material such as stainless steel or nickel-based alloys. Therefore, galvanic corrosion is not a concern for the components of the condensate and demineralized water system during the period of extended operation. The staff found the applicant's explanation to be acceptable, and RAI 3.4-6 LP is closed.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the condensate and demineralized water system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 condensate and demineralized water system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the condensate system and demineralized water system.

- Chemistry Control Program (B.2.1.5)
- Aboveground Carbon Steel Tanks Program (B.2.1.26)
- One-Time Inspection Program (B.2.1.29)
- Selective Leaching of Materials Program (B.2.1.30)
- Systems Monitoring Program (B.2.1.39)

SER Sections 3.0.3.2.2, 3.0.3.1.6, 3.0.3.1.7, 3.0.3.1.8, and 3.0.3.3.1, respectively, present the staff's detailed review of these AMPs.

During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the condensate and demineralized water system (02), no AMPs other than those identified above for the period of extended operation are noted for the extended outage. In RAI 3.4-5 LP, the staff requested the applicant to justify the basis for not performing inspections of the affected system components prior to Unit 1 restart. By letter dated October 8, 2004, the applicant stated that the one-time (restart) inspections described in the LRA will be performed prior to Unit 1 restart to verify the material condition. The staff found the applicant's commitment of performing these inspections prior to Unit 1 restart to be acceptable, and considers RAI 3.4-5 LP closed for this system. The staff's discussion of the general adequacy of the restart inspections managing the aging effects versus periodic inspections for the system components is provided in SER Section 3.7.1.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, and January 31, May 18, and 27, 2005, the staff found the applicant identified appropriate AMPs for managing the aging effects of the Unit 1 condensate and demineralized water system components exposed to an environment that lacked moisture controls. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the Unit 1 condensate and demineralized water system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.5.3.3 Heater Drains and Vents System

Technical Staff Evaluation. The technical staff reviewed the AMR of the heater drains and vents system (06) to determine whether the proposed aging management was adequate to address any potential aging during the extended shutdown of Unit 1. The heater drains and vents system is described in LRA Section 2.3.4.4. LRA Table 3.4.2.4 contains the AMR for the system for normal operation. LRA Section 3.0.1 and the applicant's February 19, 2004, submittal state that portions of Unit 1 heater drains and vents system are within the boundary of the BFN layup program. However, the portions of this system within the scope of license renewal lack moisture controls and are considered moist air control components. The applicant's February 19, 2004, submittal describes the applicant's process for evaluating the effects of aging during the extended shutdown. The staff verified that the applicant had identified all applicable AERMs during the extended shutdown and credited appropriate AMPs for managing the AERMs. The staff also reviewed the applicable UFSAR supplements for the AMPs to ensure that the program descriptions adequately describe the AMPs.

Aging Effects. Table 4 of the February 19, 2004, submittal provides the AMR of the heater drains and vents system components within the scope of license renewal that were exposed to an air environment that lacked moisture controls. The component types include bolting, fittings, piping, traps, and valves.

The applicant's February 19, 2004, submittal identified air/gas (moist air) as the internal environment of the system, whereas the external environment was inside air.

For the Unit 1 heater drains and vents system components, the applicant identified the following materials, environments, and AERMs: carbon and low-alloy steel components in air/gas (internal) moist air environments are subject to loss of material due to general, crevice, pitting, and galvanic corrosion; carbon low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion.

On the basis of its review of the information provided in the LRA, as supplemented by letter dated February 19, 2004, the staff concurred with the applicant's evaluation of the aging effects of the materials and environments associated with the heater drains and vents system during the extended shutdown. The staff did not identify any omitted aging effects. Therefore, the staff found that the applicant had identified the appropriate aging effects for the Unit 1 heater drains and vents system during the extended shutdown.

Aging Management Programs. After evaluating the applicant's identification of aging effects, the staff evaluated the AMPs to determine if they are appropriate for managing the identified aging effects from the extended shutdown. The staff also verified that the UFSAR supplement contains an adequate description of the program.

Table 4 of the applicant's February 19, 2004, submittal identifies the following AMPs for managing the aging effects described above for the heater drains and vents system.

- Chemistry Control Program (B.2.1.5)
- Flow-Accelerated Corrosion Program (B.2.1.15)
- One-Time Inspection Program (B.2.1.29)

SER Sections 3.0.3.2.2, 3.0.3.2.9, and 3.0.3.1.7, respectively, present the staff's detailed review of these AMPs. During its review, the staff determined that additional information was needed to complete its review.

In Table 4 of the February 19, 2004, submittal, for the heater drains and vents system (06), the applicant indicated that carbon and low-alloy steel components in inside air (external) environments are subject to loss of material due to general corrosion, because the components' surface temperature is less than 212 °F during the period of extended outage. The applicant indicated that the components will be inspected for external corrosion prior to Unit 1 restart, but provided no details for the inspection. In RAI 3.0-7 LP, the staff requested the applicant to discuss the proposed inspections, including scope, method, procedure, parameters monitored and trended, detection of aging effects, and acceptance criteria, in order to justify the adequacy of the inspections. By letter dated October 8, 2004, the applicant stated that external surface monitoring the affected carbon and low-alloy steel components in accordance with the Systems Monitoring Program described in the LRA, Appendix B, Section B.2.1.39 is performed. The applicant noted that this is the same AMP proposed for managing external loss of material is performed during the period of extended operation. The staff determined the Systems Monitoring Program to be adequate in managing the external aging effects. RAI 3.0-7 LP is, therefore, closed for the heater drains and vents system (06).

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19 and October 8, 2004, the staff found the applicant had identified appropriate AMPs for managing the aging effects of the Unit 1 heater drains and vents system components exposed to an environment that lacked moisture controls. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

Conclusion. On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 heater drains and vents system components during the extended shutdown, so that there is reasonable assurance that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.7.6 Containments, Structures, and Component Supports

3.7.6.1 Summary of Technical Information in the Application

In LRA Section 3.5, the applicant addressed the aging management of containments, structures and component supports. LRA Section 3.0.1 contains a summary of the Evaluation of the Unit 1 Layup and Preservation Program. By letter dated February 19, 2004, the applicant submitted additional information, entitled, Submittal of Evaluation of the BFN Unit Layup and Preservation Program, was reviewed by the staff. The staff determined that it needed additional information to complete its review.

3.7.6.2 Technical Staff Evaluation

The technical staff reviewed the applicant's AMR results for BFN containments, structures and component supports and reported its evaluation findings in SER Section 3.5. The staff also reviewed the containment and structural aspects of the applicant's evaluation of the BFN Unit 1 Layup and Preservation Program, and determined that additional information was needed to complete its review.

The staff determined that the BFN document titled, "Evaluation of the BFN Unit 1 LayUp and Preservation Program," including Tables 1 through 4, did not provide information related to BFN's evaluation of the Unit 1 spent fuel storage system layup effects. RAI 3.5-1 (related to Unit 1 layup issue) requested, by letter dated June 23, 2004, that the applicant describe the method adopted in assessing the Unit 1 spent fuel storage system related layup effects. The applicant was also asked to provide a discussion of the applicable spent fuel pool environments (any delta change in pool water chemistry, ambient humidity, and temperature, etc.), results of past periodic inspections of the spent fuel pool structural components and pool liners, any observed pool leakages or degraded conditions, and corrective actions taken to support BFN's conclusion that no layup effect is applicable to the Unit 1 spent fuel storage system.

By letter dated July 19, 2004, the applicant responded that:

> The Unit 1 spent fuel storage system was never placed in layup. The Unit 1 spent fuel storage system contains spent fuel and remained in service since Unit 1 was shut down and defueled in 1985. The Unit 1 spent fuel storage pool is located on elevation 664.0' of the Unit 1 reactor building. This area where the spent fuel pools are located is referred to as the refuel floor and is common for all three units (i.e., there are no physical barriers separating the spent fuel pools from the other units). Therefore the spent fuel pools are exposed to the same operating environments. The spent fuel storage pool chemistry is maintained in accordance with Technical Requirement Manual section TR 3.9.3 Spent Fuel Pool Water Chemistry.
>
> The spent fuel pool storage system is in service and complies with all applicable license and regulatory requirements. The structural components of the Unit 1 spent fuel storage

system are being monitored under the Maintenance Rule (Structures Monitoring Program) requirements, which are the same requirements as those for inspection of the Unit 2 and 3 spent fuel storage system. Plant procedure 0-TI-346 implements the requirements of the Maintenance Rule and contains the same performance criteria for all 3 units. The Maintenance Rule inspection results for Unit 1 spent fuel storage pool are consistent with the Maintenance Rule inspection results for Unit 2 and 3 spent fuel storage pools. The structural components of the Unit 1 spent fuel pool and the supporting equipment of the spent fuel pool storage system are all exposed to an environment that is consistent with the operating environments of the Units 2 and 3 spent fuel storage system. Any degraded condition discovered during system operation or as part of the Maintenance Rule inspection of the Unit 1 spent fuel storage system is handled the same as for the Units 2 and 3 spent fuel storage systems. The BFN Corrective Action Program to address degraded conditions is SPP-3.1. The structural components of BFN spent fuel storage system are addressed in LRA Section 2.4.2.1.

> The operating environment for the Unit 1 spent fuel storage system is consistent with the operating environments of the Units 2 and 3 spent fuel storage systems and the system has been maintained consistent with license and regulatory requirements and the plant corrective program. Therefore, there is no difference between the Unit 1 spent fuel storage system and those of Units 2 and 3. Since the system was not in layup, as described above, no layup effects are applicable to the Unit 1 system. This is the basis for not including the spent fuel storage system to the BFN document "Evaluation of the BFN Unit 1 Layup and Preservation Program."

The staff found the applicant's response, which is based on plant-specific structural configuration and operational experience, adequate and reasonable to support its assertion that no layup effects are applicable to the Unit 1 spent fuel storage system. Therefore, the RAI is considered closed.

In RAI 3.5-2 the staff requested the applicant to describe the approach used in evaluating the Unit 1 structures and component supports related layup effects. The staff also requested the applicant to provide a discussion of the environments applicable to Unit 1 structures and component supports (e.g., any exposure to aggressive chemicals or ponding of water, significant change in ambient humidity and temperature, etc.), results of past periodic inspections of the structures and component supports, any observed degraded conditions, and corrective actions taken to support BFN's conclusion that no layup effect is applicable to Unit 1 structures and component supports that require an AMR.

In its letter dated July 19, 2004, the applicant responded that:

> For Unit 1 structures and component supports, the external service environments defined in Table 3.0.2 of the LRA were used in the aging management review. An example of an environment is the "Inside Air" environment that is defined in Table 3.0.2 as "Atmospheric air, maximum average temperature 150 °F, humidity up to 100 percent, potentially exposed to ionizing radiation, not exposed to weather." The range of interior temperatures, pressures, relative humidity, and radiation dose for the reactor building and primary containment are defined in calculations ND-Q1999-900031 (RIMS W78 030430 005), "Summary of Operational Environmental Conditions for Browns Ferry Nuclear Plant," ND-Q2999-880143 (RIMS R14 020723 105), "Summary of Harsh

Environmental Conditions for Browns Ferry Unit 2" and NDQ3999- 910035 (RIMS R14 020723 104), "Summary of Harsh Environmental Conditions for Browns Ferry Unit 3." The interior temperatures, pressures, relative humidity, and radiation dose are shown on the Harsh Environmental Data Drawings 47E225 series for each unit. The environmental conditions defined in the referenced calculations are enveloped by the definition for "Inside Air" contained in Table 3.0.2, except for the area of the main steam tunnel located on elevation 565.0' of the Units 2 and 3 reactor buildings. The main steam tunnels during plant operation have an average area temperature of 160°F. This temperature occurs as a result of plant operation and has not been seen in the same area of the Unit 1 reactor building during plant lay-up. The Unit 1 lay-up environment is the same or bounded by the evaluated operating environments.

The Unit 1 reactor building structure is subject to the Maintenance Rule SMP requirements. A baseline inspection for the BFN SMP was performed in 1997. All the same attribute inspections that were performed for Units 2 and 3 were performed for Unit 1. This inspection is documented in calculation CDQ-0303-970086 (RIMS R14 971105 102). LCEI-CI-C9, "Procedure for Walkdown of Structures for Maintenance Rule," was the procedure utilized to perform SMP inspections and requires the documentation of defects in accordance with the requirements of the procedure. There were two defects noted from the inspection of the Unit 1 reactor building, and these two defects were noted as: (1) a personnel lock door that appeared to not be airtight and (2) rust was noted on some of the torus reinforcement steel between bays 12-13, 13-14, and 14-15. These defects were dispositioned as not affecting structural function. The SMP requires a reinspection on a five-year frequency. The 2002 SMP inspection is documented in calculation CDQ-0303-2003-0260 (RIMS R14 030211 102). During the 2002 SMP inspections, there were four defects noted from the inspection of the Unit 1 reactor building and which were dispositioned as not affecting structural function. These four defects were noted as: (1) a concrete pad at the floor around conduit was chipped, (2) bolt missing from angle securing the structural plate partition wall to the concrete floor, (3) in the southwest comer of a stairwell, mortar was missing at one end of the masonry block, and (4) some concrete deterioration was noted in bay 7 of the torus area (work in progress to repair the area was noted from walkdown). These defects noted from the two inspection periods can be categorized as isolated conditions and do not represent an adverse trend that will affect the functionally of structural components.

The component supports located in Unit 1, except for those that are required for Unit 2 or Unit 3 system operation, are not subject to periodic inspections during the shutdown period. All component supports for safety-related systems required for Unit 1 operation are to be inspected and existing configurations confirmed as part of the Unit 1 recovery effort. The following plant procedures (walkdown instructions [WI]), are utilized: WI-BFN-0-CEB-01 was used for piping and supports, WI-BFN-0-CEB-02 was used for structural items, and WI-BFN-0-GEN-01 was used for both piping/supports and structural steel as a general walkdown procedure. Additionally, the following procedures were used to document baseline configurations for other component supports:

WI-BFN-0-CEB-03 - Small Bore Piping
WI-BFN-0-CEB-04 - Seismic Verification of A46 and IPEEE
WI-BFN-0-CEB-05 - Pipe Rupture/HELB
WI-BFN-0-CEB-06 - Seismically Induced Water Spray

The inspections would document as-built configurations or existing plant configurations that did not conform to the acceptance criteria defined in the WI. These configurations would be evaluated to design criteria requirements. If the evaluations determined that the configuration did not meet the design criteria requirement, a plant modification would be designed and issued under the plant work control process.

An electronic search of the site Corrective Action Program for PERs was performed to identify any adverse conditions with component supports. The search did not result in the identification of any adverse conditions.

The environment for the Unit 1 structures and component supports is consistent with the operating environments of the Units 2 and 3 structures and component supports; therefore, there is no difference in the Unit 1 structures and component supports from Units 2 and 3 and no lay-up affects are applicable to Unit 1.

The staff found the above response very plant-specific and reasonably detailed to justify the applicant's assertion that the environment of the Unit 1 structures and component supports is consistent with the operating environments of the Units 2 and 3 structures and component supports; therefore, no layup effects are applicable to Unit 1 structures and component supports. RAI 3.5-2 (related to Unit 1 layup issue) is considered resolved.

In RAI 3.5-3, the staff pointed out that, when the plant is operating, the containment drywell, torus, and connecting vent assemblies are subjected to a relatively inert environment, and all the requirements related to their inspections, and leak-rate testing are applicable. These requirements ensure the leak tight and structural integrity of these components. Also, industry operating experience problems, as reflected in NRC's generic letters, information notices, and other industry published event reports are considered applicable. These activities may or may not have been considered for Unit 1 during its long layup. In this context, the applicant was requested to provide information that would describe the benchmark condition of the containment pressure boundary related components prior to Unit 1 restart, and actions that will be taken prior to the extended period of operation. The relevant regulatory requirements are 10 CFR 50,55a, and Appendix J of 10 CFR 50. The relevant generic letters are GL 87-05, GL 89-16, and GL 98-05. The relevant information notices are IN 86-99, IN 88-82, IN 89-06, IN 89-79, and IN 92-20.

In its letter dated July 19, 2004, the applicant responded that:

For the Unit 1 containment drywell and torus, the environment during the extended outage was the same as or bounded by the evaluated operating unit environments. LRA Table 3.0.2 describes the containment environment for the drywell and torus that was used in the AMR as "Atmospheric air, maximum average temperature 150 °F, humidity up to 100 percent, potentially exposed to ionizing radiation, not exposed to weather." The applicant pointed out that "Inerting was not credited for elimination of aging effects requiring aging management, and that the Unit 1 containment environment associated with temperature and ionizing radiation are not as severe as the evaluated (operating) environment conditions." The torus was subject to the torus water environment during the shutdown period. The torus was subsequently drained and is being refurbished as part of the Unit 1 recovery effort.

On the subject of containment inspections and leak-rate testing, the applicant stated that 100 percent of the examinations required in Examination Categories of Table IWE-2500-1 for the First Inspection Interval will be completed as pre-service exams before Unit 1 restarts except those that may be excluded by 10 CFR 50.55a and where specific written relief has been granted by the staff. The requirements of ASME Section XI In-Service Inspection Subsection IWE, 1992 Edition with the 1992 Addenda will be implemented on Unit 1. Type A, B, and C leak rate testing required by 10 CFR 50 Appendix J will also be performed prior to Unit 1 restart.

In addition, the applicant addressed the relevant information notices and generic letters as follows:

- NRC GL 87-05: Request Additional Information Assessment - Degradation of Mark I Drywells

The applicant provided the staff with the results of the ultrasonic testing for corrosion degradation of the drywell liner plate, RIMs No. L44 880830 801, dated August 30, 1988. The results of the ultrasonic testing state that each unit's drywell was ultrasonically tested near the sand cushion area during 1987. The results from these tests showed that the nominal thickness was maintained on each drywell. On Unit 1, no reading below the nominal thickness of one inch was measured, indicating that the integrity of the drywell liner plate was maintained.

- NRC GL 89-16: Installation of a Hardened Wet Well Vent. BFN will be installing the hardened well vent as part of the Unit 1 recovery effort. This generic letter does not address aging effects or aging management considerations.

- NRC IN 86-99: Degradation of Steel Containments. See response to GL 87-05

- NRC IN 88-82: Torus Shells with Corrosion and Degraded Coatings on BWR Containments. In 1983, Engineering Change Notice (ECN) P0555 was issued to completely inspect and recoat the torus as necessary. The Unit 1 work was completed on this ECN.

- NRC IN 89-06: Bent Anchor Bolts in Boiling Water Reactor Torus Supports. Based on the configuration of the BFN torus supports, it has been determined that BFN tie down bolts would not be subject to the effects that occurred at plant Hatch. This information notice does not address aging effects or aging management considerations.

- NRC IN 92-20: Inadequate Local Leak Rate Testing. The vent line bellows at BFN are of a different design (single-ply bellows) than the Quad Cities bellows identified in IN 92-20. The design of the BFN penetration bellows allows full pressure to be transmitted to all portions of the bellows during Appendix J testing.

In addition to the above information, the applicant addressed the staff's RAIs related to the Unit 1 primary containment during the AMR of other two units. They are discussed in SER Section 3.5.

On the basis of its review of the information provided in the LRA, as supplemented by letters dated February 19, 2004, and a teleconference held between the staff and the applicant on

April 14, 2004, the staff found that the applicant identified appropriate AMPs for managing the aging effects of the Unit 1 containment, structures, and component supports during the extended shutdown. In addition, the staff found the program descriptions in the UFSAR supplement acceptable.

3.7.6.3 Conclusion

On the basis of its review, the staff concluded that the applicant had adequately identified the aging effects and the AMPs credited for managing the aging effects for the Unit 1 containment, structures, and component supports during the extended shutdown, so that there is reasonable assurance that the intended functions of these Unit 1 structural components will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.29(a).

The staff also reviewed the applicable UFSAR supplement program descriptions and concluded that the UFSAR supplement provides an adequate description of the AMPs credited for managing aging in these components, as required by 10 CFR 54.21(d).

3.8 Conclusion for Aging Management

The staff reviewed the information in LRA Section 3, "Aging Management Review Results," and Appendix B, "Aging Management Programs and Activities." On the basis of its review of the AMR results and AMPs, the staff concluded that the applicant had demonstrated that the aging effects will be adequately managed 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 reviewed the applicable UFSAR supplement program summaries and concluded that the UFSAR supplement adequately describes the AMPs credited for managing aging as required by 10 CFR 54.21(d).

With regard to these matters, the staff concluded that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the BFN CLB in order to comply with 10 CFR 54.21(a)(3) are in accord with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

This section discusses the identification of time-limited aging analysis (TLAAs). The applicant discusses the TLAAs in license renewal application (LRA) Sections 4.2 through 4.7. Safety evaluation report (SER) Sections 4.2 through 4.8 document the review of the TLAAs conducted by the staff of the U.S. Nuclear Regulatory Commission (NRC or the staff).

The TLAAs are certain plant-specific safety analyses that are based on an explicitly assumed 40-year plant life. Pursuant to 10 CFR 54.21(c)(1), the applicant for license renewal must provide a list of TLAAs, as defined in 10 CFR 54.3.

In its letters dated June 9, 2005, and June 15, 2005, the applicant determined that LRA Sections 4.7.2, 4.7.3, and 4.7.5 should not be considered TLAAs; therefore, they were deleted from the application (See SER Sections 4.7.2, 4.7.3, 4.7.5).

In addition, pursuant to 10 CFR 54.21(c)(2), an applicant may provide a list of plant-specific exemptions granted under 10 CFR 50.12 that are based on TLAAs. For any such exemptions, the applicant must provide an evaluation that justifies the continuation of the exemptions for the period of extended operation.

4.1.1 Summary of Technical Information in the Application

To identify the TLAAs, the applicant evaluated calculations for the Browns Ferry Nuclear Plant (BFN) against the six criteria specified in 10 CFR 54.3. The applicant indicated that it had identified the calculations that met the six criteria by searching the current licensing basis (CLB). The CLB includes the updated final safety analysis report (UFSAR), engineering calculations, technical reports, engineering work requests, licensing correspondence, and applicable vendor reports. The applicant listed the following applicable TLAAs in LRA Table 4.1.1, "List of Time-Limited Aging Analyses":

- neutron embrittlement of the reactor vessel and internals
- metal fatigue
- environmental qualification of electrical equipment
- loss of prestress in concrete containment tendons
- primary containment fatigue
- reactor building crane load cycles
- corrosion – flow reduction
- dose to seal rings for the high-pressure coolant injection and reactor core isolation cooling containment isolation check valves
- radiation degradation of drywell expansion gap foam

- corrosion – minimum wall thickness
- irradiation assisted stress corrosion cracking of reactor vessel internals
- stress relaxation of core plate hold-down bolts
- emergency equipment cooling water weld flaw evaluation

Pursuant to 10 CFR 54.21(c)(2), the applicant stated that it had not identified any exemptions granted under 10 CFR 50.12 that were based on a time-limited aging analysis (TLAA), as defined in 10 CFR 54.3.

4.1.2 Staff Evaluation

In LRA Section 4.1, the applicant identified the TLAAs applicable to BFN. The staff reviewed the information to determine if the applicant had provided adequate information to meet the requirements of 10 CFR 54.21(c)(1) and 10 CFR 54.21(c)(2).

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

1. Involve systems, structures, and components that are within the scope of license renewal, as delineated in 10 CFR 54.4(a);
2. Consider the effects of aging;
3. Involve time-limited assumptions defined by the current operating term (40 years);
4. Are determined to be relevant by the applicant in making a safety determination;
5. Involve conclusions, or provide the basis for conclusions, related to the capability of the system, structure, and component to perform its intended functions, as delineated in 10 CFR 54.4(b); and
6. Are contained or incorporated by reference in the CLB.

The applicant provided a list of common TLAAs from U.S., Nuclear Regulatory Commission Regulatory Guide (NUREG)-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," (SRP-LR) dated July 2001. The applicant listed those TLAAs that are applicable to BFN, in LRA Table 4.1.1, "List of Time-Limited Aging Analyses."

As required by 10 CFR 54.21(c)(2), an applicant must provide a list of all the exemptions granted under 10 CFR 50.12 that are based on a TLAA and evaluated and justified for continuation through the period of extended operation. In its LRA, the applicant stated that each active exemption was reviewed to determine whether the exemption was based on a TLAA. The applicant did not identify any TLAA-based exemptions. On the basis of the information provided by the applicant with regard to the process used to identify TLAA-based exemptions, as well as the results of the applicant's search, the staff concluded that the applicant identified no TLAA-based exemptions that are justified for continuation through the period of extended operation, in accordance with 10 CFR 54.21(c)(2).

4.1.3 Conclusion

On the basis of its review, the staff concluded that the applicant provided an acceptable list of TLAAs, as required by 10 CFR 54.21(c)(1). The staff also confirmed that no exemptions to 10 CFR 50.12 have been granted on the basis of a TLAA, as required by 10 CFR 54.21(c)(2).

4.2 Neutron Embrittlement of Reactor Vessel and Internals

During plant service, neutron irradiation reduces the fracture toughness of ferritic steel in the reactor vessel (RV) beltline region of light-water nuclear power reactors. Areas of review to ensure that the RV has adequate fracture toughness to prevent brittle failure during normal and off-normal operating conditions are (1) upper-shelf energy (USE), (2) adjusted reference temperature (ART), (3) a low-pressure coolant injection (LPCI) reflood thermal shock analysis, (4) heatup and cooldown (pressure-temperature limits) curves, (5) Boiling Water Reactor Vessel and Internals Project (BWRVIP)-05 analysis for elimination of circumferential weld inspection, and (6) analysis of the axial welds. The adequacy of the analyses for these six areas is reviewed for the period of extended operation.

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 term. The delta RT_{NDT} is the product of a chemistry factor (CF) 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 Regulatory Guide (RG) 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," or from surveillance data. The fluence factor is dependent upon the neutron fluence. The margin term is dependent upon whether the initial RT_{NDT} is a plant-specific or a generic value and whether the CF was determined using the tables in RG 1.99, Revision 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. Revision 2 of RG 1.99 describes the methodology to be used in calculating the margin term. The mean RT_{NDT} is the sum of the initial RT_{NDT} and the delta RT_{NDT}, without the margin term. The delta RT_{NDT} and ART calculations meet the criteria of 10 CFR 54.3(a); therefore, they are considered as TLAAs.

The ART values are used in the analysis for the adjusted reference temperature for the RV material due to neutron embrittlement, the pressure-temperature limits analysis, and the reflood thermal shock analysis. The mean RT_{NDT} values are used in the analysis of the circumferential weld examination relief and the axial weld failure probability.

Appendix G of 10 CFR Part 50 provides the staff's criteria for maintaining acceptable levels of USE for the RV beltline materials of operating reactors throughout the licensed lives of the facilities. The Rule requires RV beltline materials to have a minimum USE value of 75 ft-lb in the unirradiated condition and to maintain a minimum USE value above 50 ft-lb throughout the life of the facility, unless it can be demonstrated through analysis that lower values of USE would provide acceptable margins of safety against fracture equivalent to those required by the American Society of Mechanical Engineers (ASME) Code Section XI, Appendix G. The Rule also mandates that the methods used to calculate USE values account for the effects of neutron irradiation on the USE values for the materials and incorporate any relevant RV surveillance capsule data that are reported through implementation of a plant's 10 CFR Part 50 Appendix H RV Material Surveillance Program.

RG 1.99, Revision 2, provides an expanded discussion regarding the calculation of Charpy USE values and describes two methods for determining Charpy USE values for RV beltline materials, depending on whether a given RV beltline material is represented in the plant's reactor vessel material surveillance program. If surveillance data are not available, the Charpy USE is determined in accordance with position 1.2 in RG 1.99, Revision 2. If surveillance data are available, the Charpy USE should be determined in accordance with position 2.2 in RG 1.99, Revision 2. These methods refer to Figure 2 in RG 1.99, Revision 2, which indicates the percentage drop in Charpy USE is dependent upon the amount of copper in the material and the neutron fluence. Since the analyses performed in accordance with 10 CFR Part 50 Appendix G are based on a flaw with a depth equal to one-quarter of the vessel wall thickness (1/4*t*), the neutron fluence used in the Charpy USE analysis is the neutron fluence at the 1/4*t* depth location.

The applicant described its evaluation of this TLAA in LRA Section 4.2, "Neutron Embrittlement of the Reactor Vessel and Internals." In order to demonstrate that neutron embrittlement does not significantly impact boiling water reactor (BWR) RV and vessel internals integrity during the license renewal term, the applicant included discussion of the following topics related to neutron embrittlement in LRA Section 4.2:

- reactor vessel materials upper-shelf energy reduction due to neutron embrittlement (LRA Section 4.2.1)
- adjusted reference temperature for reactor vessel materials due to neutron embrittlement (LRA Section 4.2.2)
- reflood thermal shock analysis of the reactor vessel (LRA Section 4.2.3)
- reflood thermal shock analysis of the reactor vessel core shroud (LRA Section 4.2.4)
- reactor vessel thermal limit analyses - operating pressure-temperature limits (LRA Section 4.2.5)
- reactor vessel circumferential weld examination relief (LRA Section 4.2.6)
- reactor vessel axial weld failure probability (LRA Section 4.2.7)
- irradiation assisted stress corrosion cracking (IASCC) of the recator vessel and its internals (LRA Section 4.7.6)
- stress relaxation of the core plate hold-down bolts (LRA Section 4.7.7)

4.2.1 Reactor Vessel Materials Upper Shelf Energy Reduction due to Neutron Embrittlement

4.2.1.1 Summary of Technical Information in the Application

In LRA Section 4.2.1, the applicant provided USE values for the limiting beltline materials. USE is the standard industry parameter used to indicate the maximum toughness of a material at high temperature. Appendix G of 10 CFR Part 50 requires the predicted end of life (EOL)

Charpy impact test USE value for RV materials to be at least 50 ft-lb (absorbed energy), unless an approved analysis supports a lower value. The applicant stated that the initial unirradiated test data are not available for the BFN RVs to demonstrate a minimum 50 ft-lb USE by standard methods. Therefore, EOL fracture energy was evaluated by using the equivalent margin analysis (EMA) methodology described in General Electric (GE) NEDO-32205-A, "10 CFR 50 Appendix G Equivalent Margin Analysis for Low Upper-Shelf Energy in BWR-2 through BWR-6 Vessels," which has been approved by the staff. According to the applicant, this analysis confirmed that an adequate margin of safety against fracture, equivalent to 10 CFR 50, Appendix G requirements, does exist. The EOL USE calculations satisfy the criteria of 10 CFR 54.3(a). As such, these calculations are a TLAA.

The RVs were originally licensed for 40 years with an assumed neutron exposure of less than 10^{19} n/cm^2 (E > 1.0 MeV). The CLB calculations use calculated fluences that are lower than this limiting value. The applicant stated that the design basis value of 10^{19} n/cm^2 bounds calculated fluences for the original 40-year license term for each unit. The tests performed on RV materials provided limited Charpy impact data. It was not possible to develop original Charpy impact test USE values using the methods of 10 CFR Part 50, Appendix H and ASTM E23, "Methods for Notched Bar Impact Testing of Metallic Materials," invoked by 10 CFR Part 50 Appendix G. Therefore, alternative methods approved by the staff in NEDO-32205-A were used to demonstrate compliance with the 10 CFR Part 50, Appendix G USE requirement.

Fluences were calculated for the RVs for the extended 60-year [54 EFPY (Effective Full-Power Year) for Unit 1; 52 EFPY for Units 2 and 3] licensed operating periods, using the methodology of NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation," which was approved by the staff in an SER dated September 14, 2001. The applicant used bounding fluence calculation, for each unit which included an extended power uprate[2] (EPU). The applicant provided the results for one bounding calculation for each RV and determined the peak surface fluence of 1.95×10^{18} n/cm^2 and peak 1/4*t* fluence of 1.35×10^{18} n/cm^2 for Unit 1 vessel, and peak surface fluence of 2.3×10^{18} n/cm^2 and peak 1/4*t* fluence of 1.59×10^{18} n/cm^2 for Units 2 and 3 vessels. Peak fluences were calculated at the vessel inner surface (inner diameter), for purposes of evaluating USE. The value of neutron fluence was also calculated for the 1/4*t* location into the vessel wall measured radially from the inside diameter using Equation 3 from Paragraph 1.1 of RG 1.99, Revision 2. This 1/4*t* depth is recommended in the ASME Section XI, Appendix G, subarticle G-2120 as the maximum postulated defect depth. The applicant evaluated the EOL USE by an EMA using the 54 EFPY calculated fluence for Unit 1 and the 52 EFPY calculated fluence for Units 2 and 3. As documented in the staff's SER, BWRVIP-74-A provided a generic EMA which demonstrated that BWR/3-6 plates and BWR/2-6 welds showing that percentage of reductions in USE of equal to or less than 23.5 percent and 39 percent, respectively, would meet the requirements of 10 CFR Part 50, Appendix G. The applicant provided results of the EMA for limiting welds and plates on the three RVs, which are summarized in LRA Tables 4.2.1.1 through 4.2.1.6. The applicant stated that the results are acceptable because the limiting USE percentage drop is less than the BWRVIP-74-A percentage drop acceptance criterion in all cases.

---

[2] TVA by letter dated January 7, 2005, agreed to decouple the power uprate licensing request from License Renewal Application. The safety review of this item will be further evaluated as part of the EPU review.

4.2.1.2 Staff Evaluation

Appendix G to 10 CFR Part 50, Section IV.A.1 requires, in part, that the reactor pressure vessel (RPV) beltline materials have Charpy USE values in the transverse direction for base metal and along the weld for weld material of no less than 50 ft-lb, 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 ASME Code Section XI, Appendix G.

By letter dated April 30, 1993, the Boiling Water Reactor Owners Group (BWROG) submitted NEDO-32205-A 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 demonstrated that the evaluated materials have the margins of safety against fracture equivalent to ASME Code Section XI, Appendix G in accordance with 10 CFR Part 50, Appendix G. In that 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 USE values through 40 years of operation in accordance with RG 1.99, Revision 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 value in the transverse direction for base metal and along the weld for weld material was 35 ft-lb.

GE performed an update to the USE EMA, which is documented in Electric Power Research Institute (EPRI) TR-113596, "BWR Vessel and Internals Project (VIP) BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," BWRVIP-74, September 1999. The staff review and approval of EPRI TR-113596 was documented in a letter dated October 18, 2001, from Mr. C.I. Grimes to Mr. C. Terry. The analysis in EPRI TR-113596 determined the reduction in the unirradiated Charpy USE resulting from neutron irradiation using the methodology in RG 1.99, Revision 2. Using this methodology and a correction factor of 65 percent for conversion of the longitudinal properties to transverse properties, the lowest Charpy USE at 54 EFPY for all BWR/3-6 plates was projected to be 45 ft-lb. The correction factor for specimen orientation in plates is based on NRC Branch Technical Position MTEB 5-2. The EMA acceptance criteria specified in the staff approved report BWRVIP-74, "BWR Vessel and Internals Project (BWRVIP), BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," are based on the percentage reduction in the unirradiated charpy USE values resulting from neutron radiation using the methodology in RG 1.99, Revision 2. The acceptance criteria that are specified in the BWRVIP-74 report indicate that the maximum allowable percentage reduction in USE value is 23.5 percent for the plates, and 39 percent for welds except for Linde 80 weld. Linde 80 welds are discussed later in this SER.

The staff's review of LRA Section 4.2.1 identified an area in which additional information was necessary to complete the review of the reactor vessel materials USE reduction due to neutron embrittlement evaluation. The applicant responded to the staff's request for additional information (RAI) as discussed below.

In RAI 4.2.1-1, dated December 1, 2004, the staff requested that the applicant provide the initial USE values, percentage reduction in USE values, percentage of copper, and 1/4*t* fluence at the end of the period of extended operation (including power uprate conditions) for all the plates and non-Linde 80 weld metals in the beltline region of the RVs. Since the analysis in the BWRVIP-74 is a generic analysis, the applicant submitted plant-specific information in LRA Tables 4.2.1.1 through 4.2.1.6 for BFN to demonstrate that the beltline plates and non-Linde 80 weld metals of the RVs meet the criteria in the BWRVIP-74 report at the end of the license renewal period. In its response, by letter January 31, 2005, the applicant stated that the initial USE values are not available for BFN; however, BFN has used the EMA method to demonstrate that the BFN vessels will maintain adequate fracture toughness throughout the period of extended operation. The LRA bounding value for EFPY is 54 EFPY for Unit 1 and 52 EFPY for Units 2 and 3. The values for all beltline materials for BFN are listed in Tables 4.2.1-1 through 4.2.1-3 of the applicant's response. The staff has verified the copper contents given in Tables 4.2.1-1 to 4.2.1-3 and concluded that applicant's response for all the beltline materials with the corresponding data in Reactor Vessel Integrity Data Base (RVID) is acceptable.

The applicant stated that the percentage reduction in the USE value for the limiting beltline plate base materials and non-Linde 80 beltline welds for all the units is less than the aforementioned acceptance criteria specified in BWRVIP-74. The staff also verified the reduction in the unirradiated USE values due to neutron radiation for the beltline base metals and non-Linde 80 beltline welds for all the units using the methodology in RG 1.99, Revision 2, and found that all the beltline materials meet the acceptance criteria specified in the staff-approved report BWRVIP-74, and 10 CFR Part 50, Appendix G. Therefore, the staff's concern described in RAI 4.2.1-1 is resolved.

The BWRVIP-74 establishes criteria for Linde 80 welds and other types of welds and base metals in the BWR RPVs. The criteria for Linde 80 welds require that the fracture toughness of the Linde 80 weld shall be established by using J-R curve based on copper and neutron fluence values. By letter dated November 21, 2005, the applicant revised LRA Table 4.2.1.1 to indicate that the limiting beltline circumferential weld for the BFN Unit 1 was made with Linde 80 flux. The applicant in its letter dated November 21, 2005, also provided the fracture toughness data (J-R curve based on the limiting copper and the neutron fluence at the end of the period of extended operation, which includes power uprate) and the $J_{applied}$ values for the Linde 80 weld, and concluded that the subject weld will maintain adequate fracture toughness during the extended period of operation. The staff verified the applicant's data and concluded that the BFN Unit 1 limiting circumferential Linde 80 weld would meet the acceptance criteria specified in the staff-approved BWRVIP-74 report and 10 CFR Part 50, Appendix G for the period of extended operation.

4.2.1.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of RV materials USE reduction due to neutron embrittlement in LRA Section A.3.1.1. On the basis of its review and the RAI response above, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on RV materials USE reduction due to neutron embrittlement and is, therefore, acceptable.

4.2.1.4 Conclusion

The staff reviewed the applicant's RAI response and TLAA on USE, as summarized in LRA Section 4.2.1, and determined that the RV beltline materials at BFN will continue to comply with the staff's USE requirements of 10 CFR Part 50, Appendix G throughout the periods of extended operation for the BFN units. The staff therefore concluded that the applicant's TLAA for USE is in compliance with the requirements of 10 CFR 54.21(c)(1)(ii) and that the safety margins established and maintained during the current operating term will be maintained during the periods of extended operation as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the TLAA on USE for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.2 Adjusted Reference Temperature for Reactor Vessel Materials due to Neutron Embrittlement

4.2.2.1 Summary of Technical Information in the Application

In LRA Section 4.2.2, the applicant summarized the ART determination for the RV materials due to neutron embrittlement. 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 margin term is defined in RG 1.99, Revision 2. As addressed in RG 1.99, Revision 2, delta RT_{NDT} is a function of neutron fluence. Since neutron fluence changes with time, the determination of delta RT_{NDT} (and, therefore, ART) meets the criteria of 10 CFR 54.3(a) for being a TLAA.

As described in UFSAR Section 4.2, the RVs were licensed for 40 years with an assumed neutron exposure of less than 10^{19} n/cm^2 (E > 1.0 MeV). The applicant stated that the CLB calculations use calculated fluences that are lower than this limiting value. The design basis value of 10^{19} n/cm^2 bounds calculated fluences for the original 40-year license term for all three units. The ART values were determined using the embrittlement correlations defined in RG 1.99, Revision 2.

The applicant calculated fluences for the RVs for the extended 60-year (54 EFPY for Unit 1; 52 EFPY for Units 2 and 3) licensed operating periods using the methodology of NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation," which was approved by the staff in an SER dated September 14, 2001. One bounding calculation was performed for each reactor vessel. Peak fluences, which included consideration of EPU conditions, were calculated at the vessel inner surface (inner diameter) for purposes of evaluating USE and ART. The neutron fluence values were also calculated for the 1/4*t* location into the vessel wall measured radially from the inside diameter using equation 3 from Paragraph 1.1 of RG 1.99, Revision 2. This 1/4*t* depth is recommended in the ASME Code Section XI, Appendix G, Subarticle G-2120 as the maximum postulated defect depth. The applicant calculated ART values for beltline materials 54 EFPY (Unit 1) and 52 EFPY (Units 2 and 3) based on the embrittlement correlation found in RG 1.99, Revision 2. The peak fluence, and ART values for the 60-year (54 EFPY (Unit 1) and 52 EFPY (Units 2 and 3) license operating period are presented in LRA Table 4.2.2-1. The applicant claimed that the limiting ARTs allow P-T limits that will provide reasonable operational flexibility.

4.2.2.2 Staff Evaluation

The applicant calculated the 54 EFPY (Unit 1) and 52 EFPY (Units 2 and 3) fluences for the RVs using the methodology of NEDC-32983P. Since this methodology is approved by the NRC, the calculated fluences provided in the LRA are acceptable. The applicant provided the results for one bounding calculation for each RV and determined the peak surface fluence of 1.95 x 10^{18} n/cm^2 and peak 1/4*t* fluence of 1.35 x 10^{18} n/cm^2 for, the Unit 1 vessel, and peak surface fluence of 2.3 x 10^{18} n/cm^2 and peak 1/4*t* fluence of 1.59 x 10^{18} n/cm^2 for, the Units 2 and 3 vessels. LRA Table 4.2.2.1 shows bounding fluence values for BFN for 54, 52 and 52 EFPYs of the operation, respectively.

The staff's review of LRA Section 4.2.2 identified areas in which additional information was necessary to complete the review of the ART values for RPV materials due to neutron embrittlement evaluation. The applicant responded to the staff's RAI as discussed below.

In RAIs 4.2.2(A), and 4.2.2(B), dated December 1, 2004, the staff requested that the applicant provide an explanation addressing the following issues:

a. The staff requested that the applicant explain why Unit 1 was assumed to achieve 54 EFPYs of operation in a 60-year span given its operating history. Additionally, the staff requested that the applicant provide an explanation for having a peak surface fluence value of 1.95 x 10^{18} n/cm^2 (E > 1.0 MeV) for Unit 1, while Units 2 and 3 achieve 2.3 x 10^{18} n/cm^2 (E > 1.0 MeV) at the end of 60 years.

   After reviewing the applicant's response, dated January 31, 2005, the staff determined that the applicant performed fluence calculations for Unit 1 assuming 54 EFPY of operation and for Units 2 and 3 assuming 52 EFPY of operation. Based on the peak surface and 1/4*t* fluence values, the applicant calculated USE and ART values for the limiting beltline material for each unit. The applicant stated that the reason the reported peak fluence for Unit 1 is lower than the fluence values for Units 2 and 3 is that the maximum delta RT_{NDT} and ART occurs in the circumferential weld material for Unit 1, which is located away from the peak vessel fluence location, whereas for both Units 2 and 3 maximum delta RT_{NDT} and ART occurs in the axial weld materials which corresponds to the peak fluence. Therefore, the reported peak fluence for Unit 1 has an applied axial correction factor of 0.81 and Units 2 and 3 do not have the axial correction factor. The applicant also indicated that 54 EFPY was selected for BFN units as a bounding value as part of the EPU[1] evaluation. For consistency with the EPU evaluation, the 54 EFPY value was incorporated into the LRA. The ART values are listed in Tables 4.2.2-1 through 4.2.2-6 of the applicant's response.

   The staff reviewed the applicant's response and found the explanation for using the fluence values cited for Units 1, 2, and 3 acceptable because it accounts for differences in weld location and neutron flux for each unit. The staff found that this approach is acceptable as it identifies the maximum ART values for all three units. Therefore, the staff's concern described in RAI 4.2.2 (A) is resolved.

---

[1]TVA by letter dated January 7, 2005, agreed to decouple the power uprate licensing request from License Renewal Application. The safety review of this item will be further evaluated as part of the EPU review.

b. The staff requested that the applicant provide the initial RT_{NDT} and ART values at 1/4t and vessel ID surface at the end of the period of the extended operation for all the materials in the beltline region of the BFN RVs.

The applicant provided information on the above items in Tables 4.2.2-1 to 4.2.2-6 of its response dated January 31, 2005. The staff verified the percentages of copper and nickel and the initial RT_{NDT} given in the applicant's response for all the beltline materials with the corresponding data in RVID and found them acceptable. The staff also verified the accuracy of the ART values for all the beltline materials using the methodology in RG 1.99, Revision 2 and found them acceptable. Therefore, the staff's concern described in RAI 4.2.2 (B) is resolved.

4.2.2.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of ART for RV materials due to neutron embrittlement in LRA Section A.3.1.2. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on ART for RV materials due to neutron embrittlement and is, therefore, acceptable.

4.2.2.4 Conclusion

The staff reviewed the applicant's TLAA on the calculation of ART values, as summarized in LRA Section 4.2.2 and the RAI response dated January 31, 2005, and determined that the applicant's calculation of the ART values for the RV beltline materials, as projected through the periods of extended operation for BFN, Units 1, 2, and 3, is in conformance with the recommended guidelines of RG 1.99, Revision 2. The staff therefore concluded that the applicant's TLAA for calculation of the ART values meet the requirements of 10 CFR 54.21(c)(1)(ii) and that the safety margins established and maintained during the current operating term will be maintained during the periods of extended operation as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the TLAA on ART calculations for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.3 Reflood Thermal Shock Analysis of the Reactor Vessel

4.2.3.1 Summary of Technical Information in the Application

The applicant stated that UFSAR Section 3.3.5 includes an EOL thermal shock analysis performed on the RVs for a design basis loss of coolant accident (LOCA) followed by a LPCI system initiation. The effects of embrittlement assumed in this thermal shock analysis will change with an increase in the licensed operating period. The applicant stated that this analysis satisfies the criteria of 10 CFR 54.3(a). As such, this analysis is a TLAA.

For the current operating period, a thermal shock analysis was originally performed on the RV components. The analysis assumed a design basis LOCA followed by LPCI system initiation and accounted for the full effects of neutron embrittlement at the end of the current license term of 40 years. The current analysis assumes EOL material toughness, which in turn depends on EOL ART values. The critical location for fracture mechanics analysis is at one quarter of the vessel thickness (from the inside, 1/4*t*). For this event, the peak stress intensity occurs approximately 300 seconds after the LOCA. The applicant stated that the analysis shows that 300 seconds into the thermal shock event, the temperature of the vessel wall at 1.5 inches deep (which is 1/4*t*) is approximately 400 °F. The ART values, described in LRA Section 4.2.2 and tabulated in Table 4.2.2.1, list the ART values for the limiting weld metal of the RVs. The highest calculated RV beltline material ART value is 167.7 °F (Unit 1). Using the equation for K_{IC} presented in ASME Section XI Appendix A and the maximum ART value, the material reaches upper shelf (a K_{IC} value of 200 ksi $\sqrt{in}$) at 272 °F, which is well below the 400 °F, 1/4*t* temperature predicted for the thermal shock event at the time of peak stress intensity. Therefore, the applicant claimed that the projected analysis is valid for the period of extended operation.

4.2.3.2 Staff Evaluation

The analysis assumes EOL material toughness, which in turn depends on EOL ART. The critical location for fracture mechanics analysis is at the 1/4*t* location. For the reflood thermal shock analysis of the RV, the peak stress intensity occurs at approximately 300 seconds after the LOCA. At that time, the temperature at 1/4*t* is approximately 400 °F, which is much higher than the 54 EFPY ART value167.7 °F for the limiting material of all the three BFN vessels. Therefore, the staff concurred with the applicant that the revised thermal shock analysis of the BFN vessels is valid for the period of extended operation because the ART for the limiting beltline plate material is 167.7 °F for Unit 1, which is below the 400 °F at 1/4*t* 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 period of extended operation.

4.2.3.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of reflood thermal shock analysis of the RV in LRA Section A.3.1.3. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on reflood thermal shock analysis of the RV and is, therefore, acceptable.

4.2.3.4 Conclusion

The staff reviewed the applicant's TLAA on reflood thermal shock analysis of the RV for a design basis LOCA and concluded that the applicant has demonstrated that the limiting beltline material will have adequate fracture toughness when exposed to stresses due to reflood thermal shock due to LOCA. The staff determined that this revised analysis for the period of extended operation meets the requirements of 10 CFR 54.21(c)(1)(ii) and that the safety margins established and maintained during the current operating term will be maintained during the periods of extended operation as required by 10 CFR 54.21(c)(1).

4.2.4 Reflood Thermal Shock Analysis of the Reactor Vessel Core Shroud

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 states that the radiation embrittlement may affect the ability of RV internals, particularly the core shroud, to withstand a LPCI thermal shock transient. The applicant stated that the analysis of core shroud strain due to reflood thermal shock is based on the calculated lifetime neutron fluence. In the thermal shock analysis of the RV core shrouds, the applicant considered the location on the inside surface of the core shroud opposite the midpoint of the fuel centerline as the location most susceptible to damage during a LPCI thermal shock transient because it receives the maximum irradiation. This analysis satisfies the criteria of 10 CFR 54.3(a). As such, this analysis is a TLAA.

The applicant stated that it used the approved fluence methodology discussed in LRA Section 4.2.2, and the 54 EFPY fluence at the most irradiated point on the core shroud was calculated to be 5.34×10^{21} n/cm^2 (E > 1 MeV) for BFN units. The maximum thermal shock stress due to a LPCI transient in this region will be 155,700 psi equivalent to 0.57 percent strain. This strain range of 0.57 percent was calculated at the midpoint of the shroud when it is exposed to 54 EFPY fluence. The applicant compared the calculated strain range with the measured values of percentage of elongation for annealed Type 304 stainless steel irradiated to 8×10^{21} n/cm^2 (E > 1 MeV). The measured value of percent elongation for stainless steel weld metal is 4 percent for a temperature of 297 °C (567 °F) with a neutron flux of 8×10^{21} n/cm^2 (E > 1 MeV), while the average value for base metal at 290 °C (554 °F) is 20 percent. The applicant concluded that the measured value of elongation bounds the calculated thermal shock strain amplitude of 0.57 percent and that the calculated thermal shock strain at the most irradiated location is acceptable considering the embrittlement effects for the period of extended operation.

4.2.4.2 Staff Evaluation

In the thermal shock analysis of RV core shrouds, the applicant considered the location on the inside surface of the core shroud opposite the midpoint of the fuel centerline as a location most susceptible to damage during a LPCI thermal shock transient because it receives the maximum irradiation. This fluence is calculated using the methodology of NEDC-32983P, "General Electric Methodology for Reactor Pressure Vessel Fast Neutron Flux Evaluation," which has been approved by the staff.

The staff's review of LRA Section 4.2.4 identified areas in which additional information was necessary to complete the review of the reflood thermal shock analysis of the reactor vessel core shroud evaluation. The applicant responded to the staff's RAI as discussed below.

In RAI 4.2.4-1(A), dated December 1, 2004, the staff stated that in LRA Section 4.2.4, "Reflood Thermal Shock Analysis of the RV Core Shroud and Repair Hardware," the applicant stated that the total integrated neutron flux at the end of 54 EFPY at the shroud inside surface is expected to be 5.34×10^{21} n/cm^2 (E > 1 MeV). Therefore, the staff requested that the applicant provide an explanation of whether this value is bounding at the inside shroud surface for all three units. If so, submit information whether the neutron fluence values are estimated based on the implementation of EPU[1].

In its response, by letter January 31, 2005, the applicant stated that the calculation of shroud fluence, 5.34×10^{21} n/cm^2 (E > 1 MeV) is based on the inner diameter peak flux of 3.14×10^{12} n/cm^2-sec (E > 1 MeV) for 54 EFPY, which is the lifetime used for Unit 1. Since lifetime used for BFN Units 2 and 3 is 52 EFPY, 5.34×10^{21} n/cm^2 (E > 1 MeV) fluence from Unit 1 is bounding for all the BFN units. The fluence value for the shroud inner diameter was based on the implementation of EPU conditions. After the review, the staff concurred with the applicant, and accepted the conservative bounding fluence value of 5.34×10^{21} n/cm^2 (E > 1 MeV) for all the three units.

RAI 4.2.4-1(B) and the applicant's response are addressed in SER Section 4.7.6.2 under core shroud subsection.

In RAI 4.2.4-1(C), dated December 1, 2004, the staff stated that the applicant calculated thermal strain resulting from the LPCI reflood thermal shock transient in the core shroud region. The applicant compared the calculated thermal strain with the measured values of percentage of elongation of annealed Type 304 stainless steel irradiated to 8×10^{21} n/cm^2 (E > 1.0 MeV). In a previous analysis performed by Dresden/Quad Cities, the applicant used the percentage reduction in area as a criterion to evaluate the thermal strain. Therefore, the staff requested that the applicant provide information on the measured percentage reduction in area values for the irradiated Type 304 stainless steel. The applicant should compare the results of the analysis obtained from using the reduction in area, with the ones using the percentage of elongation, and justify which of these properties is more appropriate to use in evaluating the local thermal shock strain associated with the reflood thermal shock event at the most irradiated core shroud region.

In its response, by letter January 31, 2005, the applicant submitted the following reduction in area and elongation values for irradiated stainless steel materials:

Reduction in Area

Fluence (n/cm^2, E>1MeV)	Test Temperature (°F)	Reduction in Area (%)
1×10^{21}	550	40
6.9×10^{21}	750	52.5

[1]TVA by letter dated January 7, 2005, agreed to decouple the power uprate licensing request from License Renewal Application. The safety review of this item will be further evaluated as part of the EPU review.

Elongation

Material	Fluence n/cm^2, (E>1MeV)	Test Temperature (°F)	Elongation (%)
Base	8×10^{21}	554	20
Weld	8×10^{21}	567	4

The applicant stated that the bounding shroud fluence (Unit 1) is 5.34×10^{21} n/cm^2 (E >1 MeV) for BFN, and the listed ductility values bound all three BFN shrouds. As described in LRA Section 4.2.4, the maximum thermal shock stress results in a calculated thermal shock strain amplitude of 0.57 percent. Both reduction in area and elongation values, which are values at failure, are significantly in excess of the calculated thermal shock strain at the most irradiated location. While the analysis indicates that either measure of ductility is acceptable for the period of extended operation, reduction in area is a more appropriate measure of ductility for the reflood thermal shock event. The strain associated with the reflood thermal shock event is very localized and is constrained by the surrounding bulk material. As such, it is similar to the triaxial stress condition present in the neck region (where the area reduction is taking place) during a tensile test. The percentage reduction in area is a measure of this triaxial stress state and, as such, is the most appropriate property for evaluating the effect of thermal shock on the RV core shroud. This staff position was previously approved for Dresden and Quad Cities LRA SER (NUREG-1796). The staff concluded that the thermal shock strain associated with the LOCA is less than the reduction in area or elongation, which would be expected to fail the shroud at the highest fluence point. Therefore, the staff concluded that the core shroud will have sufficient ductility during the reflood thermal shock transient during the period of extended operation. The staff accepts the applicant's analysis for the BFN units.

4.2.4.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of reflood thermal shock analysis of the RV core shroud in LRA Section A. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on reflood thermal shock analysis of the RV core shroud and is, therefore, acceptable.

4.2.4.4 Conclusion

The staff reviewed the applicant's TLAA on reflood thermal shock analysis of the RV core shroud and the applicant's responses to the RAIs and concluded that the applicant has demonstrated that the calculated thermal shock strain at the most irradiated portion of the core shroud is acceptable. The staff also accepted the applicant's conservative methodology in establishing the integrity of the most irradiated location of the core shroud during a low-pressure coolant injection thermal shock event. The staff determined that the revised analysis for the period of extended operation meets the requirements of 10 CFR 54.21(c)(1)(ii) and that the safety margins established and maintained during the current operating term will be maintained during the periods of extended operation as required by 10 CFR 54.21(c)(1).

4.2.5 Reactor Vessel Thermal Limit Analyses: Operating Pressure-Temperature Limits

4.2.5.1 Summary of Technical Information in the Application

In LRA Section 4.2.5, the applicant addressed the RV thermal limit analysis. The ART value is the sum of initial RT_{NDT} + delta RT_{NDT} + margins for uncertainties at a specific location. Neutron embrittlement increases the ART value. Thus, the minimum metal temperature at which an RV is allowed to be pressurized increases. The ART value of the limiting beltline material is used to correct the beltline P-T limits to account for irradiation effects. Appendix G of 10 CFR Part 50 requires RV thermal limit analyses to determine operating P-T limits for three categories of operation: (1) hydrostatic pressure tests and leak tests, referred to as Curve A; (2) non-nuclear heatup/cooldown and low-level physics tests, referred to as Curve B; and (3) core critical operation, referred to as Curve C. P-T limits are developed for three vessel regions: the upper vessel region, the core beltline region, and the lower vessel bottom head region. The calculations associated with generation of the P-T curves satisfy the criteria of 10 CFR 54.3(a). As such, this topic is a TLAA.

The applicant stated that the BFN Technical Specifications Section 3.4.9 contains P-T limit curves for heatup, cooldown, criticality, and inservice leakage and hydrostatic testing. According to the applicant, limits are also imposed on the maximum rate of change of reactor coolant temperature. The P-T limit curves are currently calculated for 12 EFPY (Unit 1), 17.2 EFPY (Unit 2) and 13.1 EFPY (Unit 3) operating periods. The applicant stated that new P-T limits will be calculated and submitted for approval prior to the start of extended operation.

4.2.5.2 Staff Evaluation

The applicant plans to calculate vessel P-T limit curves for all BFN units and submit them to the staff for approval before the start of the period of extended operation using an approved fluence methodology. By letter dated December 6, 2004, the applicant submitted updated P-T curves for Unit 1, which are currently being reviewed by the staff. The applicant stated that the P-T curves for Units 2 and 3 were approved by the staff as documented in safety evaluations dated March 10, 2004. The applicant's CLB allows the development of P-T limit curves consistent with the 2000 Edition, 2001 Addenda of Section XI of the ASME Code. The applicant stated that it will manage the P-T limits using approved fluence calculations when there are changes in power of core design in conjunction with surveillance capsule results from the BWRVIP integrated surveillance program. The staff found the applicant's plan to manage the P-T limits acceptable because the change in P-T curves will be implemented by the license amendment process (i.e., modifications of technical specifications) and will meet the requirements of 10 CFR 50.60 and 10 CFR Part 50, Appendix G.

4.2.5.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of RV thermal limit analyses: operating temperature and pressure limits in LRA Section A.3.1.5. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on reactor vessel thermal limit analyses: operating P-T limits and is, therefore, acceptable.

4.2.5.4 Conclusion

The staff reviewed the applicant's TLAA on P-T limits, as summarized in LRA Section 4.2.5 and determined that the applicant will generate the P-T limits for the periods of extended operation for BFN. The staff therefore concluded that the applicant's TLAA for the BFN P-T limits will meet the requirements of 10 CFR 54.21(c)(1)(ii) when the P-T limits for the periods of extended operation are generated and incorporated into the BFN technical specifications and that the safety margins established and maintained during the current operating term will be maintained during the periods of extended operation as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the TLAA on P-T limits for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.6 Reactor Vessel Circumferential Weld Examination Relief

4.2.6.1 Summary of Technical Information in the Application

LRA Sections 4.2.6 and A.3.1.6 discuss inspection of the RV circumferential welds. These sections of the LRA indicate that the applicant will use an approved relief from ultrasonic testing of RV circumferential shell welds. The applicant stated that the relief from RV circumferential weld examination requirements under GL 98-05 is based on probabilistic assessments that predict an acceptable probability of failure per reactor operating year. The analysis is based on RV metallurgical conditions as well as flaw indication sizes and frequencies of occurrence that are expected at the end of a licensed operating period. The applicant stated that Units 2 and 3 have received this relief for the remainder of their current 40-year licensed operating periods. Unit 1 submitted a relief request (currently under review by the staff) for the remainder of its 40-year licensed operating period. The circumferential weld examination relief analyses meet the requirements of 10 CFR 54.3(a). As such, they are a TLAA.

The basis for this relief request was an analysis that satisfied the limiting conditional failure probability for the circumferential welds at the expiration of the current license, based on topical report BWRVIP-05, "Reactor Vessel Shell Weld Inspection Guidelines," and the extent of neutron embrittlement. The anticipated changes in metallurgical conditions expected over the extended licensed operating period require an additional analysis for the period of extended operation and approval by the staff to extend this relief request.

The staff evaluation of BWRVIP-05 utilized the favor code to perform a probabilistic fracture mechanics (PFM) analysis to estimate the RPV shell weld failure probabilities. Three key assumptions of the PFM analysis were (1) the neutron fluence was the estimated end-of-license mean fluence, (2) the chemistry values were mean values based on vessel types, and (3) the potential for beyond design basis events (DBEs) was considered. LRA Table 4.2.6.1 provides a comparison of Units 2 and 3 RV limiting circumferential weld parameters to those used in the staff evaluation of BWRVIP-05 for the first two key assumptions. Data provided in LRA Table 4.2.6.1 were supplied from Tables 2.6.4 and 2.6.5 of the final safety evaluation of the BWRVIP-05 report.

For Units 2 and 3, the fluence is equivalent to that used in the staff analysis. However, Units 2 and 3 weld materials have significantly lower copper values (0.09 vs. 0.31) than those used in the NRC analysis. As a result, the shifts in reference temperature for Units 2 and 3 are lower than the 64 EFPY shift from the staff SER analysis. In addition, the unirradiated reference temperatures for both units are significantly lower. The combination of initial RT_{NDT} and delta RT_{NDT} without margin yields mean RT_{NDT} values for Units 2 and 3 that are considerably lower than the staff mean analysis values. Based on this analysis, the applicant concluded that the RV conditional failure probability is bounded by the staff analysis. The applicant claimed that the procedures and training used to limit cold over-pressure events will be the same as those approved by the staff when the applicant requested the relief for the current license term for Units 2 and 3.

4.2.6.2 Staff Evaluation

The technical basis for relief is discussed in the staff's final SER concerning the BWRVIP-05 report, which is enclosed in a July 28, 1998, letter from Mr. G.C. Laines (NRC) to Mr. C. Terry (BWRVIP Chairman). In this letter, the staff concluded that since the failure frequency for RV 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 below the core damage frequency of any BWR plant, the continued inspection would result in a negligible decrease in an already acceptably low value of RV failure. Therefore, elimination of the inservice inspection (ISI) for RV circumferential welds is justified. The staff's letter indicated that BWR applicants may request relief from ISI requirements of 10 CFR 50.55a(g) for volumetric examination of circumferential RV 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 staff's July 28, 1998 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 staff's SER. The letter indicated that the requirements for inspection of circumferential RV welds during an additional 20-year license renewal period would be reassessed, on a plant-specific basis, as part of any BWR LRA. Therefore, the applicant must request relief from inspection of circumferential welds during the license renewal period per 10 CFR 50.55a.

Section A.4.5 of the BWRVIP-74 report indicates that the staff's SER of the BWRVIP-05 report conservatively evaluated the BWR RVs to 64 EFPY, which is 10 EFPY greater than what is realistically expected for the end of the license renewal period. The staff used the mean RT_{NDT} value for materials to evaluate failure probability of BWR circumferential welds at 32 and 64 EFPY in the staff SER dated July 28, 1998. The neutron fluence used in this evaluation was the neutron fluence at the clad-weld (inner) interface.

Since the staff analysis discussed in the BWRVIP-74 report is a generic analysis, the applicant submitted plant-specific information to demonstrate that the beltline materials meet the criteria specified in the report. To demonstrate that the vessels for Units 2 and 3 have not become embrittled beyond the basis for the relief, the applicant, in LRA Table 4.2.6.1, supplied a comparison of 52 EFPY material data for the limiting BFN circumferential welds with that of the 64 EFPY reference case in Appendix E of the staff's SER of the BWRVIP-05 report. The BFN material data included amounts of copper and nickel, chemistry factor, the neutron fluence, delta RT_{NDT}, initial RT_{NDT}, and mean RT_{NDT} of the limiting circumferential weld at the end of the renewal period. The staff verified the data for the copper and nickel contents and the initial RT_{NDT} values for Units 2 and 3 beltline materials by comparing them with the corresponding data in the RVID maintained by the staff. The 52 EFPY mean RT_{NDT} value for Units 2 and 3 is 25 °F. The staff checked the applicant's calculations for the 52 EFPY mean RT_{NDT} values for the circumferential welds using the data presented in LRA Table 4.2.6.1 and found them accurate. These 52 EFPY mean RT_{NDT} values for Units 2 and 3 are less than the 64 EFPY mean RT_{NDT} value of 129.4 °F used by the staff for determining the conditional failure probability of a circumferential weld. The 64 EFPY mean RT_{NDT} value from the staff SER dated July 28, 1998, is for a Babcock and Wilcox (B&W) weld, because B&W welded the circumferential welds in the vessels. Since the BFN 52 EFPY mean RT_{NDT} values are less than the 64 EFPY value from the staff SER dated July 28, 1998, the staff concluded that the BFN RV conditional failure probabilities are bounded by the staff analysis.

The applicant stated that the procedures and training used to limit cold over-pressure events will be the same as those approved by the staff when the applicant requested relief for the current license period, but it did not explicitly cite a document that supports this statement. The applicant stated that the procedure and training requirements identified in the applicant's request to use the BWRVIP-05 report are provided in the document, "Safety Evaluation by the Office of Nuclear Reactor Regulation Related to Alternative to Inspection of Reactor Pressure Vessel Circumferential Welds, BFN Power Station, Units 2 and 3," (attached to staff letter to TVA; "Browns Ferry Nuclear Plant Unit 2, Relief Request 2-ISI-9, Alternatives for Examination of Reactor Pressure Vessel Shell Welds (TAC No. MA8424)," August 14, 2000; and staff letter to the applicant, "Browns Ferry Nuclear Plant Unit 3, Relief Request 3-ISI-1, Revision 1, Alternatives for Examination of Reactor Pressure Vessel Shell Welds (TAC No. MA5953)," November 18, 1999. The applicant further stated that LRA Section 4.2.6, and associated LRA Section A.3.1.6, reference the safety evaluation request letters identified above. The staff found the response acceptable because the applicant identified the requested references and commits to include them in LRA Sections 4.2.6 and A.3.1.6.

By letter dated May 12, 2004, the applicant submitted a relief request concerning the examination of the Unit 1 RV circumferential welds for the current license period.

In RAI 4.2.6-1, dated December 1, 2004, the staff requested that the applicant provide the RV circumferential weld examination relief analyses for Unit 1. In its response, by letter January 31, 2005, the applicant submitted the following relief analyses related to the Unit 1 RV circumferential weld examination:

> The following table provides a comparison of the BFN Unit 1 RV limiting circumferential weld parameters to those used in the NRC evaluation of BWRVIP-05 for the first two key assumptions. Data provided in this table was supplied from Tables 2.6.4 and 2.6.5 of the Final Safety Evaluation of the BWRVIP-05 Report (NRC letter from Gus C. Lainas to Carl Terry, Niagara Mohawk Power Company, BWRVIP Chairman, "Final Safety Evaluation of the BWRVIP Vessel and Internals Project BWRVIP-05 Report," (TAC No. M93925), July 28, 1998.

Group	B & W 64 EFPY	BFN Unit 1 54 EFPY
Cu %	0.31	0.27
Ni %	0.59	0.6
CF	196.7	184
Fluence at clad/weld interface 10^{19} n/cm^2	0.19	0.2
Delta RT_{NDT} without margin (°F)	109.4	104
Initial RT_{NDT} (°F)	20	20
Mean RT_{NDT} (°F)	129.4	124
P (F/E) NRC	4.83×10^{-4}	----------------------
P (F/E) BWRVIP	------------------	---------------------

The fluence assumed for Unit 1 is very conservative based on an extended shutdown period from 1985 to a scheduled restart in 2007, which will result in less than 32 EFPY of vessel exposure through the end of the extended period of operation. However, TVA conservatively chose to use the higher exposure of 54 EFPY to simplify the basis for the Unit 1 vessel evaluations. As shown in the table, the Unit 1 unirradiated weld RT_{NDT} is identical to the reference B&W plant unirradiated weld RT_{NDT} used in the NRC analysis, and the Unit 1 fluence value is approximately equivalent to that used in the NRC analysis. However, because the Unit 1 chemistry factor is less than the reference B&W plant, the mean RT_{NDT} values for Unit 1 at 54 EFPY are bounded by the 64 EFPY Mean RT_{NDT} assumed by the NRC in its analysis. Accordingly, Unit 1 is bounded by the conditional failure probability calculated by the Staff for the limiting B&W vessel. An extension of this relief for the 60-year period will be submitted to the NRC for approval prior to entering the period of extended operation.

The staff verified the accuracy of the of the mean RT_{NDT} for the limiting beltline circumferential weld at Unit 1 and found it acceptable. In the staff's evaluation of the BWRVIP-05 report, a fluence of 0.19×10^{19} n/cm^2 for B&W RVs was used for 64 EFPY and the corresponding delta RT_{NDT} value is 109.4 °F. The delta RT_{NDT} value for the limiting beltline weld metal of Unit 1 is less than the limiting delta RT_{NDT} value in the staff's evaluation of BWRVIP-05 report, which is conservative. Therefore, the applicant's calculated mean RT_{NDT} value for the limiting beltline weld metal is acceptable and meets the requirements specified in staff's approved SER for the BWRVIP-05 report.

The staff's SER for the BWRVIP-05 report provides a limiting conditional failure probability of 4.83×10^{-4} per reactor-year for a limiting plant-specific mean RT_{NDT} of 129.4 °F for B&W fabricated RVs. The low temperature over-pressure (LTOP) transient frequency is the frequency of the transient occurring, determined as 10^{-3} per reactor-year in the evaluation of BWRVIP-05 report. The conditional failure probability is the probability of failure, if the event were to occur. The vessel failure frequency is the product of conditional failure probability and LTOP frequency. Comparing the information in the RVID with that submitted in the analysis, the staff confirmed that the mean RT_{NDT} of the circumferential welds at Unit 1 is projected to be 124 °F at the end of the period of extended operation (54 EFPY). In this evaluation, the chemistry factor, delta RT_{NDT}, and mean RT_{NDT} were calculated consistent with the guidelines of RG 1.99, Revision 2. Since the calculated value of mean RT_{NDT} for the circumferential welds at Unit 1 is lower than that for the limiting plant-specific case for B&W fabricated RVs, the vessel failure frequencies of the Unit 1 circumferential welds is less than 4.83×10^{-7} per reactor-year.

The staff found that the applicant's evaluation for this TLAA is acceptable because the BFN 54 EFPY conditional failure probabilities for the RV circumferential welds are bounded by the staff analysis in the staff SER dated July 28, 1998, and the applicant will be using procedures and training to limit cold over-pressure events during the period of extended operation. This analysis satisfies the evaluation requirements of the staff SER dated July 28,1998; however, the applicant is still required to request relief for the circumferential weld examination for the period of extended operation in accordance with 10 CFR 50.55a.

4.2.6.3 UFSAR Supplement

The applicant's UFSAR supplement summary description for the TLAA on RV circumferential weld examination relief appropriately describes that the conditional failure probabilities for the RV circumferential welds are bounded by the staff analysis in the staff SER dated July 28, 1998, and the applicant will be using procedures and training to limit cold over-pressure events during the period of extended operation for Units 2 and 3. Since the UFSAR supplement summary description adequately describes the TLAA for Units 2 and 3, the staff concluded that the UFSAR supplement summary description for the TLAA on RV circumferential weld examination relief for Units 2 and 3 is acceptable. In addition, in a letter dated May 25, 2005, the applicant stated that the UFSAR supplement summary description also includes Unit 1 as shown in the revised supplement A.3.1.6.

4.2.6.4 Conclusion

The staff reviewed the applicant's TLAA on RV circumferential weld examination relief, as summarized in LRA Section 4.2.6, and determined that the applicant appropriately explained that the conditional failure probabilities for the RV circumferential welds are bounded by the staff analysis in the SER on the BWRVIP-05 report, dated July 28, 1998, and that the applicant will be using procedures and training to limit cold over-pressure events during the period of extended operation for BFN. However, the staff concluded that the LRA Section A.3.1.6 should include circumferential weld examination analysis for Unit 1. The staff, therefore, concluded that the applicant's LRA Section 4.2.6 on TLAA, and LRA Section A.3.1.6 for the BFN RV circumferential weld examination relief will meet the requirements of 10 CFR 54.21(c)(1)(ii), except as noted above.

4.2.7 Reactor Vessel Axial Weld Failure Probability

4.2.7.1 Summary of Technical Information in the Application

LRA Section 4.2.7 discusses the BWRVIP recommendations for inspection of RV shell welds and contains generic analyses supporting a staff SER conclusion that the axial weld failure rate is no more than 5 x 10^{-6} per reactor year. The applicant stated that the supporting evaluations described in the LRA only apply to Units 2 and 3. The axial weld failure probability analysis meets the requirements of 10 CFR 54.3(a). As such, it is a TLAA.

The applicant compared the limiting axial weld properties at 52 EFPY for Units 2 and 3 with the limiting axial weld properties provided in the supplement to NRC SER for BWRVIP-05. The limiting axial welds at Units 2 and 3 are all electroslag welds with similar chemistry. The Units 2 and 3 limiting weld chemistry, chemistry factor, and 52 EFPY mean RT_{NDT} values are within the limits of the values assumed in the analysis performed by the staff in the BWRVIP-05 SER supplement. The applicant concluded that the probability of failure for the axial welds is bounded by the staff evaluation.

4.2.7.2 Staff Evaluation

In its July 28, 1998, letter to Mr. C. Terry, the BWRVIP Chairman, the staff identified a concern about the failure frequency of axially-oriented welds in BWR RVs. In response to this concern, in letters dated December 15, 1998, and November 12, 1999, the BWRVIP supplied evaluations of axial weld failure frequency. The staff's SER on these analyses is enclosed in a March 7, 2000, letter from Mr. J. Strosnider (NRC) to Mr. C. Terry, (BWRVIP Chairman). The staff performed a generic analysis using Pilgrim Nuclear Station SER as a model for BWR RVs that were fabricated with electroslag welds, and demonstrated that a mean RT_{NDT} of 114 °F resulted in a failure frequency of 5 x 10^{-6} per reactor-year of operation. The applicant calculated, and the staff confirmed, that the limiting axial weld mean RT_{NDT} value for Units 2 and 3 at 52 EFPY is 108 °F, which supports the conclusion that the failure frequencies for Units 2 and 3 will be less than 5 x 10^{-6} per reactor-year of operation at the end of their period of extended operation. Therefore, this analysis is acceptable.

In RAI 4.2.7-1, dated December 1, 2004, the staff requested that the applicant provide an evaluation for the RV axial weld failure probability analyses for Unit 1 for the current license period, and the period of extended operation. In its response to RAI 4.2.7-1, by letter dated January 31, 2005, the applicant provided the following evaluation on the RV axial weld failure probability analysis for Unit 1:

> The table provided below compares the limiting axial weld 54 EFPY properties for Unit 1 against the values taken from Table 2.6.5 found in the NRC SER for BWRVIP-05 and associated supplement to the SER (NRC letter from Jack R. Strosnider, to Carl Terry, BWRVIP Chairman, "Supplement to Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report," (TAC No. MA3395), March 7, 2000). The SER supplement required the limiting axial weld to be compared with data found in Table 3 of the document. For Unit 1 the comparison was made to the 'Mod 2' plant information. The supplemental SER stated that the 'Mod 2' calculations most closely match the 5 x 10^{-6} RV failure frequency.

Effects of Irradiation on RV Axial Weld Properties BFN Unit 1:

Value	NRC BWRVIP-05 SER MOD 2	BFN Unit 1 54 EFPY
Cu %	0.219	0.24
Ni %	0.996	0.37
CF	------	141
Fluence at clad/weld interface 10^{19} n/cm^2	0.148 (Peak Axial Fluence)	0.24
ΔRT_{NDT} without margin (^{0}F)	116	86
$RT_{NDT(U)}$ (°F)	-2	23
Mean RT_{NDT} (°F)	114	109
P (F/E) NRC	5.02 x 10^{-6}	Not Calculated

The limiting axial weld is an electroslag weld with similar chemistry. The Unit 1 limiting weld chemistry, chemistry factor, and 54 EFPY mean RT_{NDT} values are within the limits of the values assumed in the analysis performed by the NRC staff in the BWRVIP-05 SER supplement and the 64 EFPY limits and values obtained from Table 2.6.5 of the SER. Therefore, the probability of failure for the axial welds is bounded by the NRC evaluation.

In this evaluation, the chemistry factor delta RT_{NDT} and mean RT_{NDT} were calculated consistent with the guidelines of RG 1.99, Revision 2. The applicant calculated, and the staff confirmed, that the limiting axial weld mean RT_{NDT} value for Unit 1 at 54 EFPY is 109 °F. This value is lower than that for the limiting mean RT_{NDT} value of 114 °F in the staff's evaluation of BWRVIP-05. Therefore, the staff concluded that the failure frequencies for Unit 1 axial welds will be less than 5 x 10^{-6} per reactor-year of operation. The probability of failure for the axial welds is bounded by the staff evaluation.

4.2.7.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of RV axial weld failure probability in LRA Section A.3.1.7. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on RV axial weld failure probability and is, therefore, acceptable. In addition, in a letter dated May 25, 2005, the applicant stated that the UFSAR supplement summary description also includes Unit 1 as shown in the revised supplement A.3.1.7.

4.2.7.4 Conclusion

The staff reviewed the applicant's TLAA on the evaluation of RV axial weld failure probabilities, as summarized in LRA Section 4.2.7, and determined that the applicant appropriately describes that the analyses of the conditional failure probabilities for the BFN Units 2 and 3 RV axial welds is bounded by the NRC analysis in the staff SER on the BWRVIP-05 report, dated July 28, 1998. However, the UFSAR supplement summary description in LRA Section A.3.1.7 should include the analysis on the conditional failure probabilities for the Unit 1 RV axial welds. The staff therefore concluded that the applicant's LRA Sections 4.2.7, and A.3.1.7 related to the analysis of the conditional failure probabilities for the BFN units RV axial welds are acceptable. The staff concluded that the analysis of the RV axial weld failure probability for the BFN units will meet the requirements of 10 CFR 54.21(c)(1)(ii), except as noted above.

4.3 Metal Fatigue

A metal component subjected to cyclic loading at loads less than the static design load may fail due to fatigue. Metal fatigue of components may have been evaluated based on an assumed number of transients or cycles for the current operating term. The validity of such metal fatigue analysis is reviewed for the period of extended operation. The GALL Report identifies fatigue aging related effects that require evaluation as possible TLAAs, pursuant to 10 CFR 54.21(c). Each of these is summarized in the SRP-LR and presented in LRA Section 4.

4.3.1 Reactor Vessel Fatigue Analysis

4.3.1.1 Summary of Technical Information in the Application

In LRA Section 4.3.1, "Reactor Vessel Fatigue Analyses," the applicant stated that the original pressure vessel stress report included ASME Code Section III fatigue analyses of the RV components based on a set of design basis transients and corresponding cycles, which are listed in UFSAR Section 4.2.5. The analyzed components consisted of the vessel support skirt, shell, upper and lower heads, closure flanges, nozzles and penetrations, nozzle safe ends, and closure studs. The original 40-year analysis demonstrated that the cumulative usage factors (CUFs) for these components are below the ASME Code Section III limiting value of 1.0. A re-analysis was performed for BFN to determine the CUFs of these components under EPU and Maximum extended load line limit analysis conditions, for 60 years of operation. LRA Table 4.3.1.1 lists the results of this re-analysis for seven bounding reactor vessel components. These components are the recirculation outlet nozzle, recirculation inlet nozzle, feedwater nozzle, core spray nozzle, the support skirt, the closure stud bolts, and the vessel shell. This table shows that for Units 2 and 3, the recirculation outlet nozzles, the feedwater nozzles, the support skirts and the closure stud bolts, all have 60-year projected CUFs that exceed the ASME Code Section III Class 1 limiting value of 1.0. These results also bound the projected CUFs for Unit 1.

The applicant stated that fatigue aging of the seven components listed in LRA Table 4.3.1-1 will be managed by the Fatigue Monitoring Program (LRA Section B.3.2) for the period of extended operation.

The applicant also stated that the original ASME Code analysis of the reactor vessel also included fatigue analyses of the feedwater nozzles and the control rod drive (CRD) hydraulic system return line nozzles. After several years of operation, these nozzles were found to be susceptible to cracking caused by a number of factors, including rapid thermal cycling. The CRD hydraulic system return line nozzles were therefore capped and removed from service. As such, they are no longer susceptible to rapid thermal cycling. A re-analysis was performed on the feedwater nozzles and modifications were implemented to reduce or eliminate the effects of the high thermal cycling, based on generic BWROG guidance.

Based on its evaluation, the applicant concluded that, for some components, the fatigue analyses of the reactor vessel will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i), or that for the remaining vessel components, the effects of aging will be adequately managed for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

4.3.1.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.3.2, pertaining to the fatigue analysis of reactor vessel components. The CLB fatigue analyses of components associated with the reactor vessels were identified as TLAAs, in accordance with the provisions of 10 CFR 54.3(a) and the components listed in the appropriate tables in the GALL Report. The applicant listed the bounding CUFs associated with these TLAAs and indicated that the CUFs for four vessel components would exceed the ASME Code Section III Class 1 limiting value of 1.0 during the period of extended operation. The applicant, therefore, committed to monitor the fatigue of these vessel components as part of the Fatigue Monitoring Program, which provides for monitoring fatigue stress cycles to ensure that the CUF limit of 1.0 is not exceeded. The staff found this acceptable and concurred with the applicant that the effects of aging of the reactor vessel components for BFN will be adequately managed with the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii) The staff also found acceptable that, for those components where the CUF did not exceed 1.0, the fatigue analyses were projected to remain valid to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

In accordance with 10 CFR 54.21(d), the applicant's supplement for the UFSAR regarding the reactor vessel fatigue TLAAs is provided in LRA Section A.3.2.1. The staff reviewed this supplement and found it acceptable because it provides a reasonable summary of the information presented in LRA Section 4.3.1.

4.3.1.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of reactor vessel fatigue analyses in LRA Section A.3.2.1. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the reactor vessel fatigue TLAAs and is, therefore, acceptable.

4.3.1.4 Conclusion

The staff reviewed the applicant's TLAA on the reactor vessel fatigue analyses, as summarized in LRA Section 4.3.1, and determined that the metal fatigue assessments at Units 1, 2, and 3 will continue to comply with the staff's requirements throughout the period of extended operation. The staff, therefore, concluded that the applicant's TLAA for reactor vessel fatigue analyses meets the requirements of 10 CFR 54.21(c)(1)(ii), (iii), and that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the TLAA on reactor vessel fatigue analyses for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.2 Fatigue Analysis of Reactor Vessel Internals

4.3.2.1 Summary of Technical Information in the Application

In LRA Section 4.3.2, "Fatigue Analysis of Reactor Vessel Internals," the applicant stated that the original fatigue evaluation of the reactor vessel internals was performed using ASME Code Section III as a guide. The evaluation determined that the most significant fatigue loading occurs at the jet pump diffuser-to-baffle-plate weld location. The fatigue analysis of this location was the only fatigue analysis actually performed. Since this analysis was based on a number of cycles for a 40-year life, it is considered a TLAA. The calculated CUF was 0.35, less than the ASME Code Section III Class 1 allowable CUF of 1.0. Since the original fatigue analysis was based on a 40-year design life, the calculation for the jet pump diffuser-to-baffle-plate weld was projected for a 60-year life by multiplying the CUF by 1.5, which resulted in a CUF less than the ASME Code allowable of 1.0.

The applicant also stated that at Unit 3, a lower section of the core spray line was replaced, and a repair was installed to address cracking found at the location of the core spray-to-T-box weld. Fatigue calculations were performed for several components of the core spray line using ASME Code Section III as a guide, since the core spray line is not classified as an ASME Code Section III component. However, these analyses are considered as TLAAs since they were based on a 40-year life. A fatigue evaluation of the lower core spray line sectional replacement was performed, resulting in a maximum calculated CUF of 0.45, based on a 40-year design life. An explicit fatigue calculation was also performed for the T-box repair, based on a 40-year design life. The CUF was calculated to be 0.022. The fatigue calculation for the core spray-to-T-box weld repair was evaluated for a lifetime of 60 years by multiplying the 40-year CUF by 1.5, which resulted in a 60-year CUF that is less than the ASME Section III Class 1 limit of 1.0. The fatigue analysis is, therefore, acceptable for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). The applicant also concluded that these results are applicable for BFN.

The applicant stated that the core spray-to-T-box weld location is also included for inspection as part of the Boiling Water Reactor Vessel Internals Program (LRA Section B.2.1.12). These inspections will be used to manage the effects of potential cracking of these welds.

For the lower core spray sectional replacement, the design life was specified as 40 years. However, since this modification was installed more than 20 years into the current licensing period, the applicant concluded that these fatigue calculations will remain valid for the period of extended operation.

Based on the revised fatigue analyses, the applicant concluded that, in accordance with 10 CFR 54.21(c)(1)(i), the fatigue analyses for the reactor internals remain valid for the period of extended operation or, in accordance with10 CFR 54.21(c)(1)(ii), the fatigue analyses have been projected to the end of the period of extended operation. The applicant also stated that, in accordance with 10 CFR 54.21(c)(1)(iii), the effects of aging on the intended function(s) of the reactor vessel internals for the BFN units will be adequately managed for the period of extended operation.

4.3.2.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.3.2 pertaining to the fatigue analysis of reactor vessel internals. Based on the reported CUFs corresponding to the reported fatigue analyses, the staff concurred with the applicant that the fatigue analyses for the reactor vessel internals remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i), or that the fatigue analyses have been projected to the end of the period of extended operation, in accordance with10 CFR 54.21(c)(1)(ii). The staff also found acceptable that the effects of aging on the intended function(s) of the reactor internals for BFN will be adequately managed with the Fatigue Monitoring Program for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

In accordance with 10 CFR 54.21(d), the applicant's supplement for the UFSAR regarding the fatigue analyses of reactor vessel internals is provided in LRA Section A.3.2.2. The staff reviewed this supplement and found it acceptable. It provides a reasonable summary of the information presented in LRA Section 4.3.2.

4.3.2.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of the fatigue analysis of reactor vessel internals in LRA Section A.3.2.2. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the reactor vessel internals fatigue TLAAs and is, therefore, acceptable.

4.3.2.4 Conclusion

The staff reviewed the applicant's reactor vessel internals fatigue TLAAs, as summarized in LRA Section 4.3.2, and determined that the metal fatigue assessments at BFN Units 1, 2, and 3 will continue to comply with the staff's requirements throughout the period of extended operation. The staff, therefore, concluded that the applicant's evaluation of reactor vessel internals fatigue TLAAs meets the requirements of 10 CFR 54.21(c)(1)(i) - (iii), and that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the

TLAA on fatigue analysis of reactor vessel internals for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.3 Piping and Component Fatigue Analysis

4.3.3.1 Summary of Technical Information in the Application

In LRA Section 4.3.3, "Piping and Components Fatigue Analysis," the applicant stated that the reactor coolant pressure boundary (RCPB) and non-RCPB piping was designed to USA Standard (USAS) B31.1. This code does not require an explicit fatigue analysis. However, the RCPB and non-RCPB piping within the scope of license renewal that is designed to USAS B31.1 requires the application of a stress reduction factor to the allowable thermal stress range if the number of full range cycles exceeds 7000.

The applicant indicated that the assumed thermal cycle count for the analyses can be approximated by the thermal cycles used in the reactor vessel fatigue analysis. These thermal cycles are listed in UFSAR Section 4.2.5. The total count of all these listed thermal cycles is fewer than 1100 over the 40-year plant life. For the 60-year extended operating period, the number of assumed operating cycles would be increased to 1650, considerably fewer than the 7000 cycle threshold in USAS B31.1. In accordance with 10 CFR 54.21(c)(1)(i), the applicant concluded that the existing piping analyses within the scope of licence renewal will remain valid for the period of extended operation.

4.3.3.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.3.3, pertaining to the fatigue analysis of piping and components. The applicant indicated that the RCPB and non-RCPB piping and components at BFN, within the scope of license renewal, were designed to USAS B31.1-1967. Although this Code does not require explicit fatigue analysis, it considers fatigue implicitly in the design calculations by applying a stress range reduction factor to the allowable thermal stress range, which depends on the number of design thermal expansion cycles. The staff, therefore, concurred with the applicant that qualifications of piping to this code are considered TLAAs, in accordance with the provisions of 10 CFR 54.21(c)(1).

In the application of USAS B31.1-1967, the applicant approximated the number of thermal expansion cycles over a 40-year plant life by the thermal cycles used in the reactor vessel fatigue analysis. These thermal cycles are listed in UFSAR Section 4.2.5. For a 60-year plant life, the total count of all significant full thermal cycles was determined as fewer than 1650, which is substantially less than the 7000-cycle full thermal stress range limit in USAS B31.1. The staff concurred with the applicant that an adequate margin of safety for the RCPB and non-RCPB systems will be maintained for the period of extended operation, because the projected number of thermal operating cycles to the end of the period of extended operation is fewer than the design cycle limit of 7000 cycles, and the stress range limits in the current piping calculations therefore remain valid. The staff, therefore, concurred with the applicant that the existing piping analyses, within the scope of license renewal, will remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

In accordance with 10 CFR 54.21(d), the applicant's supplement for the UFSAR regarding the piping and component fatigue analyses is provided in LRA Section A.3.2.3. The staff reviewed this supplement and found it acceptable because it provides a reasonable summary of the information presented in LRA Section 4.3.3.

4.3.3.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of piping and component fatigue analysis in LRA Section A.3.2.3. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the piping and component fatigue TLAA and is, therefore, acceptable.

4.3.3.4 Conclusion

The staff reviewed the applicant's piping and component fatigue TLAA, as summarized in LRA Section 4.3.3, and determined that the metal fatigue assessments at BFN Units 1, 2, and 3 will continue to comply with the staff's requirements throughout the period of extended operation. The staff therefore concluded that the applicant's piping and component fatigue TLAA meets the requirements of 10 CFR 54.21(c)(1)(ii), and that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the piping and component fatigue TLAA for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.4 Effects of Reactor Coolant Environment On Fatigue Life of Components and Piping (Generic Safety Issue 190)

4.3.4.1 Summary of Technical Information in the Application

In LRA Section 4.3.4, "Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping (Generic Safety Issue 190)," the applicant described the actions taken to address the issue of environmentally assisted fatigue. Generic Safety Issue (GSI) 190 addresses the effects of reactor coolant environment on the fatigue life of components and piping. Although GSI 190 is resolved, SRP-LR Section 4.3.1.2 states that for licence renewal, the applicant's consideration of the effects of coolant environment on component fatigue life is an area of review.

The applicant stated that plant-specific calculations were performed for the following fatigue sensitive component locations, identified in NUREG/CR 6260 for older-vintage BWRs:

- reactor vessel shell and lower head
- reactor vessel feedwater nozzle
- reactor recirculation piping (outlet and inlet nozzles)
- core spray system (nozzle and safe end)
- residual heat removal (RHR) line Class 1 piping

- feedwater line Class 1 piping

The applicant stated that for each location listed above, detailed environmental fatigue calculations for 60 years were performed using the appropriate environmental fatigue life correction factor (F_{en}) relationships from NUREG/CR 6583 "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," for carbon and alloy steels, and the appropriate F_{en} relationships from NUREG/CR 5704 "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," for stainless steel, as appropriate for the material. These evaluations are consistent with the recommendations in SRP-LR Section 4.3.2.2 for addressing the effects of the reactor coolant environment by assessing the effects on a sample of critical components. The 60-year CUF for the reactor recirculation piping was determined as 4.181, and the 60-year CUF for the feedwater line Class 1 piping was calculated as 1.489. In accordance with 10 CFR 54.21(c)(1)(iii), the applicant stated that all necessary plant transients will be tracked using the Fatigue Monitoring Program, to ensure that CUF values will remain below 1.0 for the period of extended operation. For the locations where the CUF is expected to exceed 1.0 for the 60-year period, the applicant stated that additional fatigue analyses will be performed prior to the period of extended operation, and appropriate action will be taken if the EOL CUF values above 1.0 are projected.

4.3.4.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.3.4 pertaining to the effects of reactor coolant environment on the fatigue analysis of components and piping.

GSI-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of the RCS components. 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 that:

> The results of the probabilistic analyses, along with the sensitivity studies performed, the iterations with industry (Nuclear Energy Institute (NEI) and EPRI), and the different approaches available to the licensees to manage 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 leaks as plants continue to operate. Thus, the staff concluded 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 evaluated the component locations listed in NUREG/CR-6260 that are applicable to an older-vintage BWR plant for effect of the environment on the fatigue life of the components. For each location, detailed environmental fatigue calculations were performed using the appropriate F_{en} relationships from NUREG/CR 6583, "Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels," for carbon and alloy steels, and those from NUREG/CR 5704, "Effects of LWR Coolant Environments on Fatigue on Fatigue Design Curves of Austenitic Stainless Steels," for stainless steel, as appropriate for the material. These calculations showed that two locations were projected to exceed the CUF limiting value of 1.0 prior to the end of the period of extended operation. In accordance with 10 CFR 54.21(c)(1)(iii), the applicant committed to track all necessary plant transients, using the BFN Fatigue Monitoring Program, to ensure that the CUF values will remain below 1.0 for the period of extended operation. For those locations where the CUF is expected to exceed 1.0 for the 60-year period, the applicant stated that additional analyses will be performed prior to the period of extended operation, and appropriate action will be taken if the end-of-life CUF values are projected to be above 1.0.

The staff found the environmental fatigue effects assessment acceptable, since this evaluation is consistent with the recommendations in SRP-LR Section 4.3.2.2 for addressing the effects of the reactor coolant environment by assessing the effects on a sample of critical components. The staff also found acceptable the applicant's commitment to use the Fatigue Monitoring Program to assure that the CUFs at the critical locations will not exceed the limiting CUF value of 1.0 during the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(iii).

In accordance with 10 CFR 54.21(d), the applicant included a section addressing the effects of reactor coolant environment on fatigue life of components and piping (Issue 190) in LRA Section A.3.2.4. The applicant committed to include the locations that have projected CUF values greater than 1.0 in the Fatigue Monitoring Program. The staff found this supplement acceptable because it provides a reasonable summary of the information presented in LRA Section 4.3.4.

4.3.4.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of GSI 190 in LRA Section A.3.2.4. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on GSI 190 and is, therefore, acceptable.

4.3.4.4 Conclusion

The staff reviewed the applicant's TLAA on GSI 190, as summarized in LRA Section 4.3.4, and determined that the metal fatigue assessments at BFN Units 1, 2, and 3 will continue to comply with the staff's requirements throughout the period of extended operation. The staff therefore concluded that the applicant's TLAA for GSI 190 meets the requirements of 10 CFR 54.21(c)(1)(iii), and that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21(c)(1). The staff also concluded that the UFSAR supplement contains an appropriate summary description of the TLAA on GSI 190 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 electrical components includes all long-lived, passive and active electrical and instrumentation and controls (I&C) components that are important to safety and located in a harsh environment. The harsh environments of the plant are those areas that are subjected to the environmental effects of a LOCA or a high-energy line break (HELB). The EQ equipment comprises SR and Q-list equipment; nonsafety-related (NSR) equipment, the failure of which could prevent satisfactory accomplishment of any SR function; and necessary post-accident monitoring equipment.

As required by 10 CFR54.21(c)(1), the applicant must provide a list of EQ TLAAs in the LRA. The applicant shall demonstrate that one of the following is true for each type of EQ equipment: (1) the analyses remain valid for the period of extended operation; (2) the analyses have been projected to the end of the period of extended operation; or (3) the effect of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.4.1 Summary of Technical Information in the Application

The EQ Program for Units 2 and 3 was established to verify that all plant equipment within the scope of 10 CFR 50.49 is qualified for its application and meets its specified performance requirements when subjected to the conditions predicted to be present when it must perform its safety function up to the end of its qualified life. The EQ Program for Unit 1 will be established to ensure compliance with 10 CFR 50.49. The EQ Program complies with the requirements of 10 CFR 50.49(e)(5) for aging considerations that affect functionality and make provisions to replace the components or establish ongoing qualification when the demonstrated qualified life has expired. The EQ-related equipment is identified in a controlled equipment data base with a qualification binder that is maintained with records on performance specifications, electrical characteristics, and environmental conditions.

The EQ Program manages thermal, radiation and cyclic aging as applicable for all electrical components within the scope of 10 CFR 50.49. Compliance with 10 CFR 50.49 provides evidence that the component will perform its intended functions during and after a DBE after experiencing the effects of in-service aging.

The applicant chose Option (iii) of 10 CFR 54.21(c)(1) in its TLAA evaluation to demonstrate that aging effects of the EQ equipment identified in this TLAA will be managed during the period of extended operation by the EQ Program activities. Maintaining qualification through the extended license renewal period requires that existing EQ evaluations be reanalyzed. A summary of the applicant's application of these 10 CFR 50.49(f) methodologies to the EQ evaluations for the period of extended operations follows:

> Analytical Methods - The analytical models used in the re-analysis of an aging evaluation are the same as those applied during the initial qualification. The Arrhenius methodology is an acceptable thermal model for performing an aging evaluation. The analytical method used for a radiation aging evaluation is to demonstrate qualification for the total integrated dose (i.e., 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 (i.e., 60 years/40 years). The result is added to the accident radiation dose to obtain the total integrated dose for the component. Cyclical aging will be reevaluated for those components subject to this effect.

Data Collection and Reduction Methods - Reducing excess conservatism in the service conditions used in the aging evaluation is one method that can be used in a re-analysis. Evaluations based on actual plant temperature data will, in certain cases, yield desired results for extended service life. Should the applicant opt to use this approach, plant temperature data can be obtained in several ways, including plant monitors, measurements taken by plant personnel, and temperature sensors on various plant equipment. Similar methods of reducing excess conservatism in the component service conditions may be also be used for radiation and cyclical aging.

Underlying Assumptions - Environmental excursions identified during plant operation or maintenance activities that could affect the qualification of an EQ component will be evaluated. Should unexpected adverse conditions be identified, the affected EQ component is evaluated and appropriate corrective actions taken, which may include changes to the qualification basis and conclusions reached, or restructuring of the affected component's EQ requirements.

Acceptance Criteria and Corrective Actions - If the qualification cannot be extended by re-analysis using the above methodologies, the component will be refurbished, replaced, or requalified prior to exceeding the period for which the current qualification remains valid.

The applicant stated that the 10 CFR 50.49 EQ Program is consistent with the guidance provided for resolution in the NRC Regulatory Issue Summary 2003-09, "Environmental Qualification of Low-Voltage Instrumentation and Control Cables." The regulatory issue summary states:

> For license renewal, a re-analysis (based on the Arrhenius methodology) to extend the life of the cables by using the available margin based on a knowledge of the actual operating environment compared to the qualification environment, coupled with observations of the condition of the cables during walk-downs, was found to be an acceptable approach. Monitoring I&C cable condition could provide the basis for extending cable life.

The EQ Program allows re-analysis for maintaining qualification using the methods described above. In addition, the EQ Program has the following procedural requirements in place to monitor and track aging effects.

- Detecting degradation of materials or equipment performance by requiring preventive maintenance and periodic surveillance.
- Failure trend evaluations related to equipment and environments.
- Notification of environmental excursions and subsequent evaluation of components.
- Review of licensing, industry, and other generic industry operating experience.

4.4.2 Staff Evaluation

A site-wide EQ Program required by 10 CFR 50.49 has been developed for BFN, and implemented on Units 2 and 3, and it is expected to be implemented on Unit 1 to ensure compliance with 10 CFR 50.49. This item is discussed in SER Section 2.6.1.4.

The staff's review of LRA Section 4.4 identified areas in which additional information was necessary to complete the review of the EQ evaluation. The applicant responded to the staff's RAI as discussed below.

In RAI 4.4-2, dated November 4, 2004, the staff stated that the provisions of 10 CFR 50, Appendix A, General Design Criteria (GDC) 4 require that all equipment (electrical and mechanical) related to safety be designed to accommodate the environmental effects of postulated accidents. Similarly, Standard Review Plan (SRP) 3.11 (NUREG-0800) applies equally to mechanical and electrical equipment. Therefore, the staff requested the applicant to provide a discussion of the materials for mechanical equipment in the LRA that are required to be evaluated as an EQ TLAA that are sensitive to environmental effects (e.g., seals, gaskets, lubricants, fluids for hydraulic systems, diaphragms, and wear cycle aging from lubricant deterioration) and the aging analyses that will be, or have been, conducted to satisfy the requirements of 10 CFR 54.21(c)(1) for the period of extended operation.

In its response, by letter December 20, 2004, the applicant stated that BFN was licensed before the establishment of NRC GDC-4, "Environmental and Dynamic Effects of Design Basis," and NUREG-0800. Consequently, neither GDC-4 nor SRP 3.11 are part of BFN's CLB. Therefore, the applicant does not have a formal mechanical equipment qualification program. As part of the application review process, the applicant performed searches of Industry Guidance (SRP-LR and NEI 95-10), the UFSAR, the Operating Licenses and License Conditions, Technical Specifications, Technical Requirements Manuals, and Licensing Basis Program Documents such as In-Service Inspection and EQ for possible TLAA's. For the type of mechanical equipment described above, the only TLAA found was "Dose to Seal Rings for the High Pressure Coolant Injection and Reactor Core Isolation Cooling Containment Isolation Check Valves," SER Section 4.7.3. On the basis of its review, the staff found that the applicant had adequately addressed the concern and the issue is resolved.

In RAI 4.4-1, dated November 4, 2004, the staff requested the applicant to provide a list of components covered under EQ TLAA. In its response, by letter December, 9, 2004, the applicant provided the list of components covered under the EQ TLAA. On the basis of its review, the staff found that the applicant had adequately addressed the concern and the issue is closed.

The staff reviewed the information in LRA Section 4.4 to determine whether the applicant demonstrated that the effects of aging on the intended function(s) of electrical components will be adequately managed through its existing EQ Program, together with other plant programs/processes, during the period of extended operation as required by 10 CFR 54.21(c)(1)(iii).

The applicant's program activities establish, demonstrate, and document the level of qualification, qualified configuration, maintenance, surveillance, and replacement requirements necessary to meet 10 CFR 50.49. Qualified life is determined for equipment within the scope of the EQ Program and appropriate actions, replacement or refurbishment are taken prior to or at the end of qualified life of the equipment so that aging limits or acceptable margins are not exceeded.

On the basis of its review, the staff concluded that the applicant had addressed the issues associated with GSI-168. The applicant will continue to manage the effects of aging through the EQ Program for the period of extended operation. The staff found that the applicant had satisfactorily addressed GSI-168 for license renewal, as required by 10 CFR 54.21(c)(1)(iii). The staff issued Regulatory Issue Summary (RIS) 2003-09 on May 2, 2003, to inform addressees of the results of the technical assessment of GSI-168. This RIS requires no action on the part of the addressees. Therefore, the staff considers GSI-168 issue to be resolved.

4.4.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of the TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of EQ in LRA A.3.3. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on EQ and is, therefore, acceptable.

4.4.4 Conclusion

On the basis of its review, the staff concluded that the applicant demonstrated that the effect of aging on the intended function(s) of electrical and I&C components will be adequately managed for the period of extended operation by the existing EQ Program as required by 10 CFR 54.21(c)(1)(iii).

4.5 Loss of Prestress in Concrete Containment Tendons

The BFN containments do not have prestressed tendons. As such, this topic is not a TLAA applicable for BFN.

4.6 Primary Containment Fatigue

Cyclic loads acting on the primary containment and the attached piping and components include reactor building interior temperature variation during the heatup and cooldown of the RCS, a postulated LOCA, annual outdoor temperature variations, thermal loads on containment penetrations due to high-energy piping lines (such as steam and feedwater lines), seismic loads, and pressurization due to periodic Type A integrated leak-rate tests.

Metal containment penetration sleeves (including dissimilar metal welds) and penetration bellows may be designed in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code. If a plant's code of record requires a fatigue analysis, then this analysis may be a TLAA and must be evaluated in accordance with 10 CFR 54.21(c)(1) to ensure that the effects of aging on the intended functions of the containment sleeves and bellows will be adequately managed for the period of extended operation.

In LRA Section 4.6, the applicant referenced UFSAR Section C.5.1, which states that the primary containment vessels for Units 1 and 2 were designed in accordance with the ASME Code Section III 1965 Edition with Addenda up through Winter 1966. The primary containment vessel for Unit 3 was designed in accordance with the ASME Code Section III1965 Edition with Addenda up through Summer 1967. Subsequently, while performing large-scale testing for the Mark III containment system and in-plant testing for the Mark I containment system, new hydrodynamic loads were identified for the suppression chamber (also referred to as the torus), that were not included in the original structural analyses. These additional loads result from blowdown into the suppression chamber during a postulated LOCA, and from main steam relief valve operation during plant transients. The results of structural analyses for BFN under these effects were reported in the BFN Torus Integrity Long-Term Program Plant Unique Analysis Report (PUAR). This program is described in UFSAR Section C.5.3. The applicant indicated that modifications of the suppression chamber and the suppression chamber vents, including the vent headers and downcomers, were required in order to re-establish the original design safety margins. The safety margins for these components were determined based on the allowable stresses stated in Subsection NE of the 1977 ASME Boiler and Pressure Vessel Code, Section III, including Summer 1977 Addenda.

As part of the review of the Torus Integrity Long-term Program PUAR, the applicant identified the following fatigue analyses as TLAAs:

- fatigue of the torus, vents, and downcomers
- fatigue of torus-attached piping and safety relief valve discharge lines
- fatigue of vent line and process penetration bellows

In analyzing and determining the disposition of these TLAAs for the period of extended operation, the applicant applied the following criteria:

1. The applicant stated that locations with a 40-year CUF of 0.666 are not considered as having adequate analytical or event margin when linearly extrapolated to 60 years. A CUF limit of 0.4 was chosen as providing this margin. Disposition option 10 CFR 54.21(c)(1)(i) was therefore applied to locations with a calculated 40-year CUF less than 0.4.
2. For locations where the 40-year CUF is greater than 0.4, the applicant stated that fatigue will be managed by the Fatigue Monitoring Program described in LRA Section B.3.2. Disposition option 10 CFR 54.21(c)(1)(iii) will, therefore, be applied to these locations.

4.6.1 Fatigue of Suppression Chamber, Vents, and Downcomers

4.6.1.1 Summary of Technical Information in the Application

The applicant stated that the BFN Torus Integrity PUAR includes fatigue analyses of the torus and torus vents, including the vent headers and downcomers. These analyses assumed a limited number of main steam safety relief valve (SRV) actuations and are, therefore, TLAAs.

Based on recorded plant data extrapolated to 40 years, the BFN Torus Integrity PUAR assumed 500 SRV actuations during 40 years of normal operations and the contribution from the postulated worst-case LOCA. The worst-location and the corresponding fatigue CUFs were determined as follows:

- 0.681, at the intersection of the vent headers with the downcomers
- 0.373, at the downcomer/tiebar intersection
- 0.37, for the torus restraint snubbers

Since only the SRV loads contribute to fatigue during normal operation, normal operation may continue so long as the CUF contribution from SRV actuations has not exceeded 1.0 minus the CUF contribution expected from the postulated worst-case LOCA phenomena.

The applicant indicated that, based on operating experience, the total number of SRV actuations is not expected to exceed 500 actuations for any unit during the period of extended operation. This expectation is based on an estimate of the total number of SRV actuations expected for each unit until the end of the period of extended operation. The applicant described the methodology used for estimating the total number of SRV actuations. It was based on estimating the number of SRV actuations from the start up of each unit through August 2003, an estimate of the number of valve actuations expected for the remainder of the current licensing term and for the requested period of extended operation.

The applicant stated that, based on this methodology, the number of SRV actuations from the startup of each unit through August 2003 was estimated to be 146 actuations for Unit 1, 254 actuations for Unit 2 (worst case), and 188 actuations for Unit 3. (These estimates included both planned and unplanned SRV actuations.) The estimated total number of SRV actuations from August 2003 until the end of the period of extended operation was projected to be 239 for Unit 2. Thus, the estimated total number of SRV actuations at the end of the period of extended operation for Unit 2 is 493. This is the worst-case estimate of the total number of SRV actuations expected at the end of the period of extended operation. Thus, the assumed number of 500 SRV actuations for the three units is considered to be conservative.

To ensure that corrective actions are taken before any CUF approaches 1.0, the applicant indicated that, in accordance with 10 CFR 54.3(c)(1)(iii), the applicant will manage the high CUF locations for the period of extended operation by monitoring the SRV actuations using the Fatigue Monitoring Program.

4.6.1.2 Staff Evaluation

The staff reviewed the LRA regarding the fatigue TLAAs of the torus, vents and downcomers. The staff also reviewed the applicant's disposition of these TLAAs and found it acceptable because it specified the threshold limit of CUF equals 0.4 for 40 years of operation as a criterion for determining if the fatigue analyses performed under the PUAR will remain valid for the period of extended operation. The staff concurred with the applicant that this criterion will provide additional analytical or event margin over the minimum CUF value of 0.666 for the period of extended operation. Those locations, by not exceeding the threshold criterion, will therefore remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). In accordance with 10 CFR 54.21(c)(1)(iii), for locations where the CUF exceeds the criterion above, the staff found the applicant's commitment to manage the effects of fatigue for the period of extended operation with the Fatigue Monitoring Program acceptable because it will provide assurance that the monitored CUF at a location will not exceed the ASME Code Section III CUF limiting value of 1.0; or, if the CUF is projected to exceed this limit, the applicant committed to take appropriate corrective action to assure that this limit will not be exceeded, as stated in LRA Section 4.6, in accordance with the Fatigue Monitoring Program. As described in LRA Section B.3.2, the Fatigue Monitoring Program will include an enhancement to monitor the fatigue of the torus and torus vents, and the vent headers and downcomers, using an EPRI-licensed cycle counting and fatigue usage tracking computer program. The applicant also committed to implement this enhancement prior to the period of extended operation.

In accordance with 10 CFR 54.21(d), the applicant's supplement for the UFSARs regarding the suppression chamber, vents, and downcomers fatigue TLAAs is provided in LRA Section A.3.4 "Containment Fatigue." The staff reviewed this supplement and found it acceptable because it provides a reasonable summary of the information presented in LRA Section 4.6.1.

4.6.1.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of metal fatigue analyses of suppression chamber, vents, and downcomers in LRA Section A.3.4.

4.6.1.4 Conclusion

On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the metal fatigue TLAAs of suppression chamber, vents, and downcorners and is, therefore, acceptable.

4.6.2 Fatigue of Torus Attached Pipe and Safety Relief Valve Discharge Lines

4.6.2.1 Summary of Technical Information in the Application

In LRA Section 4.6.2, the applicant stated that there are thirteen Target Rock dual-mode MSRVs to allow blowdown from the main steam piping in the drywell to the suppression pool via individual discharge lines passing through the main vents. These lines enter the suppression chamber through penetrations in the suppression chamber vent header and the steam is discharged to the suppression pool water through T-quenchers attached to the ends of the lines. There are, in addition, a number of other external piping systems attached to the suppression chamber shell.

The torus integrity PUAR indicates that an evaluation of the fatigue effects of Mark I containment cyclic "new loads" on main steam relief valve discharge lines internal to the suppression chamber and on torus-attached piping external to the suppression chamber was performed using a program developed by the Mark I Owners Group.

The fatigue analyses assumed 500 SRV actuations for a 40-year plant lifetime, and included the effects of both mechanical and thermal expansion load cycling. These analyses are, therefore TLAAs. The analyses concluded that the worst location on the main steam safety relief valve (MSRV) discharge lines would have a fatigue CUF of less than 0.35 at the end of 40 years of operation. The analyses also concluded that the worst location on the torus attached piping would have a fatigue CUF of less than 0.103 at the end of 40 years of operation. The applicant concluded that, for the MSRV discharge lines and T-quenchers, the MSRV discharge line penetrations, the torus attached piping systems, and the associated penetration locations, the predicted 60-year CUF will, therefore be less than 0.666 (worst-case CUF is 0.35 x 60/40 = 0.53). The applicant thus concluded that the MSRV discharge lines and the torus-attached piping fatigue analyses will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.6.2.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.6.2 regarding the fatigue TLAAs of the torus attached piping and the SRV discharge lines. The staff reviewed the applicant's disposition of these TLAAs and found it acceptable because the applicant selected a threshold limit of CUF equals 0.4 for 40 years of operation as a criterion for determining whether the fatigue analyses performed under the PUARs will remain valid for the period of extended operation. Based on this criterion, the staff concurred with the applicant's disposition of these TLAAs, since it demonstrated that the highest 40-year CUFs will not exceed the threshold limit of 0.40. These locations will therefore remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

In accordance with 10 CFR 54.21(d), the applicant's supplement for the UFSARs regarding the fatigue TLAAs of the torus attached piping and the SRV discharge lines is provided as part of LRA Section A.3.4. The staff reviewed this supplement and found it acceptable because it provides a reasonable summary of the information presented in LRA Section 4.6.2.

4.6.2.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation." The applicant provided a UFSAR supplement summary description of fatigue of torus attached pipe and SRV discharge lines in LRA Section A.3.4.

4.6.2.4 Conclusion

On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the metal fatigue TLAA of torus attached pipe and SRV discharge lines and is, therefore, acceptable.

4.6.3 Fatigue of Vent Line and Process Penetration Bellows

4.6.3.1 Summary of Technical Information in the Application

The applicant stated in LRA Section 4.6.3 that the torus vent line bellows are flexible expansion joints allowing movement of the main vent pipes through the torus wall without developing significant interaction loads, and maintaining the required pressure boundary. The analysis of the suppression chamber bellows is described in the PUAR and was performed in accordance with Standards of the Expansion Joint Manufacturers Association, Inc. The design life of the bellows is stated in UFSAR Section C.5.2 as 7000 thermal cycles over the 40-year life for the plant and the fatigue analyses are, therefore, TLAAs.

Containment pipe penetrations that must accommodate pipe thermal movement also have expansion bellows. Containment process piping expansion joints between the drywell shell penetrations and process piping are the only ones subject to significant thermal expansion and contraction. The design life of these bellows is also stated as 7000 operating thermal cycles over the design life at containment normal, test, and limiting design pressures throughout the 40-year life for the plant and are, therefore, TLAAs.

For the suppression chamber vent line bellows and the containment penetration bellows, thermal cycles are imposed by the thermal expansion cycles experienced by the attached piping. The assumed thermal cycle count for the analyses used in the codes associated with the piping and components can be conservatively approximated by the full thermal cycles (not including power reductions) used in the reactor vessel fatigue analysis listed in UFSAR Section 4.2.5. The applicant stated that the total count of all full thermal cycles (not including power reductions) is less than 1100 for a 40-year plant life. For the 60-year plant life, the number of thermal cycles for piping analyses would be proportionally increased to less than 1650, which is less than 25 percent of the 7000-cycle design life.

Since the suppression chamber bellows and the containment penetration bellows metal fatigue analyses have a large design fatigue life margin, the applicant concluded that the analyses will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

4.6.3.2 Staff Evaluation

The staff reviewed the technical information in LRA Section 4.6.3 regarding the metal fatigue TLAAs of the vent line bellows and the containment process piping penetration bellows. The staff concurred with the applicant's disposition of this TLAA and found it acceptable because it demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the number of full thermal cycles expected by the end of the period of extended operation will not exceed the 7000-cycle design-life of these bellows.

In accordance with 10 CFR 54.21(d), the applicant's supplement for the UFSAR regarding the metal fatigue TLAAs of the vent line and process penetration bellows is provided in LRA Section A.3.4. The staff reviewed this supplement and found it acceptable. It provides a reasonable summary of the information presented in LRA Section 4.6.3.

4.6.3.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of metal fatigue analyses of vent line and process penetration bellows in LRA Section A.3.4.

4.6.3.4 Conclusion

On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the metal fatigue TLAAs of vent line and process penetration bellows and is, therefore, acceptable.

4.7 Other Plant-Specific Analyses

In LRA Section 4.7, the applicant provided its evaluation of plant-specific TLAAs. The TLAAs evaluated include the following:

- reactor building crane load cycles
- corrosion – flow reduction
- dose to seal rings for the high pressure coolant injection and reactor core isolation cooling containment isolation check valves
- radiation degradation of drywell expansion gap foam
- corrosion – minimum wall thickness
- irradiation assisted stress corrosion cracking of reactor vessel internals
- stress relaxation of core plate hold-down bolts
- emergency equipment cooling water weld flaw evaluation

4.7.1 Reactor Building Crane Load Cycles

4.7.1.1 Summary of Technical Information in the Application

The applicant stated in Section 4.7.1 that the 125-ton reactor building overhead crane serves three reactor units and includes a 5-ton auxiliary load hoist. The crane is designed to meet the design loading requirements of the Crane Manufacturers Association of America (CMAA) Specification 70. For cyclic loading, CMAA 70 specifies that a crane classified as Service Class A1 is limited to 100,000 loading cycles over the design life. The applicant's analysis identifies that the total number of expected cycles for this crane over the entire life including construction, the 60-years of operation for all three units, and the decommissioning, has been conservatively estimated at less than 21,00 loading cycles. Of these, less than 1000 lifts are expected to be more than 90 percent of the rated capacity. The applicant concluded that the analysis of the 125-ton reactor building crane qualifies the passive structural components for extended life in accordance with CMAA 70 Service Class A1 requirements.

4.7.1.2 Staff Evaluation

During its review of the applicant's analysis the staff determined that additional information was needed to complete its review. The staff identified that TVA letter dated September 28, 1982, in response to NUREG-0612, stated that the structural and rotating parts of the crane were designed for infinite life. In RAI 4.7.1-1, the applicant was requested to clarify if infinite life is still valid or to explain the derivation of the total number of loading cycles estimated. In this RAI, the applicant was also requested to explain the difference between the 21,000 cycles estimated in

LRA Section 4.7.1 and the 7,500 cycles estimated in LRA Section B.2.1.20. Further, the applicant was requested to clarify if additional loading cycles caused by vibration during crane operation are considered in the analysis or are the basis for not including loading cycles induced by vibration. By letter dated January 12, 2005, the applicant explained that its letter dated September 28, 1982, is based on an endurance limit of 40 percent of the tensile strength which, although reasonable, is not in accordance with CMMA 70; therefore, the results of the evaluation for license renewal supercede the September 28, 1982, results provided to the NRC. The applicant also clarified that the 7,500 lifts are full-load equivalent cycles, and that the estimated load lifts are less than 1,000 near-rated lifts, less than 10,000 moderate-load lifts, and less than 10,000 light-load lifts. In regard to vibration, the applicant's response clarified that a review of operating experience indicates that vibration in the structural components has not been noticed or reported for the reactor building crane. The applicant identified that non-structural vibration and wear issues have been reported. For example, motor generator vibration has been reported, measured, and promptly corrected. The staff determined that the applicant's response satisfactorily answers the staff's technical concerns, and all items related to RAI 4.7.1-1 are resolved.

Based on its review of the applicant's analysis included in the LRA and additional clarifications provided by the applicant in response to RAI 4.7.1-1, the staff concurred with the applicant that the reactor building crane has been evaluated and is qualified for the period of extended operation. The crane is qualified for a 100,000-cycle design life, which exceeds the estimated load cycles for the life of the crane including life extension. Hence counting actual load cycle is is not required for the reactor building crane because estimated load cycles are well below the limits for the crane established by CMAA 70. Therefore, fatigue life is not significant to the operation of this equipment, and the analysis is valid for the period of extended operation. The applicant provided a satisfactory validation of 10 CFR 54.21(c)(1)(i). The staff also reviewed the UFSAR Supplement A.3.5.1 and determined that the UFSAR Supplement includes an appropriate summary description of the reactor building crane load cycles TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d).

4.7.1.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided UFSAR supplement summary description of reactor building crane load cycles in LRA Section A.3.5.1. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on reactor building crane load cycles and is, therefore, acceptable.

4.7.1.4 Conclusion

On the basis of its review, the staff concluded that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i) that the analyses remain valid for the reactor building crane load cycles TLAA. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the reactor building crane load cycles TLAA evaluation for the period of extended operation, as required by 10 CFR 54.21(d). Therefore, the staff has reasonable assurance that the safety margins established and maintained during the current operating term will be maintained during the period of extended operation, as required by 10 CFR 54.21 (c)(1).

4.7.2 Corrosion – Flow Reduction

LRA Section 4.7.2 originally considered a design calculation that addresses concerns whether the flow reduction due to corrosion in carbon steel piping used in raw water systems is a TLAA. In a letter dated June 15, 2005, the applicant provided additional information. The functional basis for determining the acceptability is based on periodic flow testing as described in the Technical Instruction 0-TI-171 RHRSW Sump Pump Flow Test, Surveillance Instruction 0-SI-4.5.C.1(4) EECW System Annual Flow Rate Test, Surveillance Instruction 1/2/3-SI-4.5.C.1(3) RHRSW Pump and Header Operability and Flow Test, and Surveillance Instructions 0-SI-4.11.B.1.g for Fire Protection Piping. Based on its further review, the applicant determined that the calculation should not be considered to be a TLAA; therefore, this section is deleted from the application.

4.7.3 Dose to Seal Rings for the High Pressure Coolant Injection and Reactor Core Isolation Cooling Containment Isolation Check Valves

Although this TLAA was included in the initial LRA, the applicant by its letter dated June 9, 2005, made a review of the safety determination per 10 CFR 54.3, and stated as follows:

> LRA Section 4.7.3 originally considered a design calculation that determines the dose to seal rings on the high-pressure coolant injection system and reactor core isolation cooling system testable check valves to be a TLAA. After further review, the applicant determined that the calculation is used to validate the seal design, but is not relied on to make a safety determination. The ability of the valve to perform its safety function is verified by Type C leak testing performed per BFN Technical Instruction 0-TI-360, "Containment Leak Rate Programs." Based on this further review, the applicant determined that the calculation should not be considered to be a TLAA, and that Section 4.7.3, "Dose To Seal Rings For The High Pressure Coolant Injection And Reactor Core Isolation Cooling Containment Isolation Check Valves," should be deleted from the LRA.

The staff concurred with the applicant's assessment that this is not a TLAA and its determination not to include it in the safety evaluation.

4.7.4 Radiation Degradation of Drywell Expansion Gap Foam

4.7.4.1 Summary of Technical Information in the Application

In LRA Section 4.7.4, the applicant stated that the steel drywell shell is enclosed in reinforced concrete for shielding purposes and to provide additional resistance to deformation and buckling of the drywell over areas where the concrete backs up the steel shell. The drywell is separated from the reinforced concrete by a gap of approximately 2 inches and filled with polyurethane foam.

4.7.4.2 Staff Evaluation

In RAI 4.7.4-1, dated December 10, 2004, the staff stated that LRA Table 3.5.2.2 lists the aging management review (AMR) results of expansion joint (elastomer, polyurethane foam) as a TLAA and refers the TLAA to LRA Section 4.7. LRA Section 4.7.4, "Radiation Degradation of Drywell Expansion Gap Foam," states that an analysis of the effect of dose on the foam showed that the material properties will remain within the limits assumed by the original design analysis for the additional 20 years of extended operation. Therefore, the staff requested the applicant to provide a more detailed discussion of the analysis,[1] including a discussion of the method and assumptions adopted in the analysis, the type of data extrapolation applied, and the quantitative results obtained to justify the applicant's assertion that the requirements of 10 CFR 54.21(c)(1)(i) are fully met.

In its response, by letter dated January 31, 2005, the applicant stated that:

> The TLAA analysis determines that the total dose to the polyurethane foam located between the drywell steel and the reactor building concrete will result in a total dose of less than 1.0E8 rads. The material properties of the polyurethane foam will remain within the limits assumed by the original analysis for a total dose of less than 1.0 E08 rads.
>
> The analysis model consists of the standard geometry sphere with a steel clad of 0.825 inches (drywell steel thickness). The radius of the sphere is 33.5 feet. Computer code QAD-P5Z, which is a point kernel variation of QAD-P5F, was used to determine dose and/or exposure rates. The computer code PARINT integrated the dose rates over time. The principle gamma source from normal operation is N-16; therefore the photon spectrum for normal operation is for N-16 with an arbitrary 1 Ci activity as input. The resultant dose rate was then scaled to the appropriate power level. The STP computer code determined the time dependent photon spectra. STP is the standard TVAN computer code for source term development. Gamma and neutron attenuation are considered.
>
> Actual power conditions are utilized in the TLAA analysis. This applies for roughly the first 25% of plant life during which time each unit was down for a significant amount of time. For conservatism, it is assumed that EPU starts October 24, 2003, even though Unit 1 has yet to be restarted. Prior to October 24, 2003, Units 2 and 3 are at 105% (uprate) conditions. For an additional conservatism, Permali neutron shielding has not been included in the TLAA analysis.
>
> The foam will only receive the significant dose from the drywell. The drywell is surrounded by a minimum of 5 feet of concrete. It is clear that the drywell sources will have a greater impact than any sources in the reactor building. The reactor building source impact will be negligible compared to the drywell.

---

[1]TVA by letter dated January 7, 2005, agreed to decouple the power uprate licensing request from License Renewal Application. The safety review of this item will be further evaluated as part of the EPU review.

> The maximum dose for 60 year operation at EPU conditions without Permali neutron shielding occurs for Unit 2 and is 9.92E+07 which is less than a total dose of 1.0E08 rads used in the original analysis. Therefore, the material properties of the polyurethane foam will remain within the limits assumed by the original analysis.

In addition, the staff requested the applicant to provide tests or other research publication based justification for making the following assertion that: "The material properties of the polyurethane foam will remain within the limits assumed by the original analysis for a total dose of less than 1.0 E08 rads."

In its letter dated May 24, 2005, the applicant responded with the following:

> The basis for asserting that the polyurethane foam will maintain its material properties when exposed to radiation dosage is BFN UFSAR Section 5.2.3.2 which states in part "... *Irradiation tests have shown that no change in the resilient characteristics will take place for exposures up to* 10^8R." This is in accordance with BFN's current licensing basis. Additionally, this same information is presented in Section 4.7.4, "Summary Description," of the LRA.

The staff found that the applicant provided adequate engineering analysis results and related material test data to fully resolve the RAI. Therefore, the staff's concern described in RAI 4.7.4-1 is resolved.

4.7.4.3 UFSAR Supplement

UFSAR Section 5.2.3.2 states that irradiation tests have shown that no change in the resilient characteristics will take place for exposures up to 1.0×10^8 rads. This test-based material performance data, in conjunction with the above-discussed TLAA analysis results, form the basis for the staff's determination that the effects of aging due to radiation degradation of drywell expansion gap foam will be adequately managed. The applicant provided UFSAR supplement summary description of drywell expansion gap foam in LRA Section A.3.5.3. On the basis of its review, the staff concluded that the UFSAR supplement summary adequately describes the TLAA in LRA Section 4.7.4, "Radiation Degradation of Drywell Expansion Gap Foam."

4.7.4.4 Conclusion

The staff reviewed the applicant's TLAA on radiation degradation of drywell expansion gap foam, as summarized in LRA Section 4.7.4, including information submitted in response to the staff's RAI and determined that the effects of aging due to radiation degradation of drywell expansion gap foam will be adequately managed. Therefore, the staff concluded that the applicant has demonstrated that the effects of aging due to radiation degradation of drywell expansion gap foam will be adequately managed 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(c)(1)(iii).

4.7.5 Corrosion – Minimum Wall Thickness

Although this TLAA was included in the initial LRA, the applicant by its letter dated June 15, 2005, made a review of the safety determination per 10 CFR 54.3, and stated as follows:

LRA Section 4.7.5 originally considered a design calculation that shows corrosion/erosion resulting in decreasing pipe wall thickness to be a TLAA. The functional basis for ensuring the wall thickness acceptability is accomplished by inspection, testing, and monitoring activities performed by plant procedures implementing SPP-9.7, Corrosion Control Program. Based on its further review, the applicant determined that the calculation should not be considered a TLAA; therefore, this section is deleted from the application.

The staff concurred with the applicant's assessment that this is not a TLAA and with its determination not to include in the safety evaluation.

4.7.6 Irradiation Assisted Stress Corrosion Cracking of Reactor Vessel Internals

4.7.6.1 Summary of Technical Information in the Application

The applicant in LRA Section 4.7.6 provided the following description for the TLAA on IASCC in austenitic stainless steel RV internal components:

> Austenitic stainless steel reactor internal components exposed to neutron fluence greater than 5×10^{20} n/cm^2 (E > 1 MeV) are considered susceptible to Irradiation Assisted Stress Corrosion Cracking (IASCC) in the BWR environment. As described in the SER (ML003776810, 12/07/2000) to BWRVIP-26, "BWR Top Guide Inspection and Flaw Evaluation Guidelines," IASCC of reactor internals is considered a TLAA. Fluence calculations have been performed for the RV and internals. Four components have been identified as being susceptible to IASCC for the period of extended operation: (1) Top Guide; (2) Shroud; (3) Core Plate and (4) In-core Instrumentation Dry Tubes and Guide Tubes.
>
> The top guide, shroud, core plate and in-core instrumentation dry tubes and guide tubes are considered susceptible to IASCC. The aging effect associated with IASCC, crack initiation and growth, will require aging management. Three components, top guide, shroud and incore instrumentation dry tubes and guide tubes, have been evaluated by the BWRVIP, as described in the Inspection and Evaluation Guidelines for each component: BWRVIP-26 (Top Guide), BWRVIP-76 (Shroud), and BWRVIP-47 (in-core instrumentation dry tubes and guide tubes). BFN implements the BWRVIP recommendations, as described in B.2.1.5 (Chemistry Control Program) and B.2.1.12 (BWR Vessel Internals Program). The core plate has been determined to be susceptible to IASCC and this is considered a plant-specific TLAA. BFN will manage this TLAA with two aging management programs: Chemistry Control Program (B.2.1.5) and BWR Vessel Internals Program (B.2.1.12). For the period of extended operation, the BWR Vessel Internals Program will perform inspections of the core plate in the regions of the highest fluence.

4.7.6.2 Staff Evaluation

The staff reviewed the information provided by the applicant in the LRA and determined that the austenitic stainless steel materials that are located in the following RV internal components are exposed to neutron fluence greater than 5×10^{20} n/cm^2 (E > 1 MeV) and are considered susceptible to IASCC in the BWR environment: (1) top guide, (2) shroud, (3) core plate, and (4) in-core instrumentation dry tubes and guide tubes. The applicant stated that the aging effects due to IASCC in the aforementioned components are managed by two aging management programs (AMPs): (1) Chemistry Control Program, and (2) Boiling Water Reactor Vessel Internals Program. The Boiling Water Reactor Vessel Internals Program in turn addresses several BWRVIP inspection programs that are designed for various RV internal components. In addition, the Boiling Water Reactor Vessel Internals Program invokes the ASME Section XI Subsections IWB, IWC, and IWD Inservice Inspection Program. The applicant claimed that implementation of these AMPs provides reasonable assurance that the aging effects due to IASCC will be managed so that the systems and components within the scope of this program will continue to perform their intended functions, consistent with the CLB, for the period of extended operation. The applicant committed to implement the relevant BWRVIP programs to manage aging effects that are associated with each of the aforementioned components. The staff, in the following paragraphs, discusses the effectiveness of these AMPs in managing the aging effect due to IASCC in each of the aforementioned components.

Top Guide - In addition to the implementation of the Chemistry Control Program, and the Boiling Water Reactor Vessel Internals Program, the applicant committed to invoke the inspection guidelines that are specified in the BWRVIP-26, "Boiling Water Reactor Top Guide Inspection and Flaw Evaluation Guidelines," which has been approved by the staff. The implementation of these additional guidelines and the AMPs is consistent with the GALL AMP XI.M9. The staff found that, by implementing a proper chemistry program as dictated by the Chemistry Control Program, the oxidizing nature of the RCS water can be controlled and, thereby, the corrosion of the top guide can be controlled.

In RAI B.2.1.12-1(A), dated December 1, 2004, the staff indicated that the BWRVIP-26 report lists 5×10^{20} n/cm^2 (E > 1.0 MeV) as the threshold fluence beyond which components may be susceptible to IASCC. According to the generic analysis in BWRVIP-26, the location on the top guide that will see a fluence equal to or greater than 5×10^{20} n/cm^2 (E > 1.0 MeV) is the grid beams. This is location 1, as identified in BWRVIP-26, Table 3-2, "Matrix of Inspection Options." In its evaluation of the top guide assembly in BWRVIP-26, GE assumed a lower allowable stress value, acknowledging the high fluence value at this location. The conclusion of GE's analysis, and the fact that a single failure at this location has no safety consequence, was that no inspection was necessary to manage IASCC in top guide grid beams.

The staff was concerned that multiple failures of the top guide grid 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 Nuclear Power station. In order to exclude the top guide grid beams from inspection when their fluence exceeds the threshold value, it must be demonstrated that failure of 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 cannot be demonstrated, then an inspection program to manage this aging effect to preclude loss of component intended function is required.

In its response, by letter dated January 31, 2005, the applicant indicated that LRA Section 4.7.6 considered the fluence at the top guide as a TLAA. The applicant manages this TLAA with the Chemistry Control Program and the BWRVIP. The BWRVIP implements the requirements of NRC-accepted BWRVIP-26. The NRC letter to Carl Terry, BWRVIP Chairman, dated June 10, 2003, states the following: "The staff believes that a comprehensive evaluation of the impact of IASCC and multiple failures of the top guide beams is necessary, and that an inspection program for top guide beams for all BWRs should be developed by the BWRVIP to ensure that all BWRs can meet the requirements of 10 CFR Part 54 throughout the period of extended operation." The applicant made a commitment, as part of the BWRVIP, to work to resolve these issues generically. When resolved, the applicant will follow the BWRVIP recommendations resulting from that resolution. Prior to the period of extended operation, the applicant will develop a site-specific inspection program, if necessary, to manage the effects of IASCC in the top guide.

The staff determined that the applicant was required to submit, for NRC review and approval, a site-specific AMP that addresses potential multiple failures of the top guide grid beams. The applicant, in its response dated May 25, 2005, indicated that it will perform inspections of the guide beams similar (in inspection methods, scope and frequency of inspection) to the inspections specified in the BWRVIP-47, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," for the control rod guide tube components. The applicant stated that the extent of examination and its frequency will be based on a ten percent sample of the total population, which includes all grid beam and beam-to-beam crevice slots, within 12 years and five percent of the population is to be completed within six years. The applicant stated that the program to inspect the top guide grid beams will be implemented prior to the end of the current license period. The sample locations selected for examination will be in areas that are exposed to highest neutron fluence. The staff found this response acceptable because it defines a representative population of IASCC susceptible locations, and selects locations in the top guide that are exposed to the highest neutron fluences. In addition, the proposed inspection requirements were previously accepted by the staff in the SE related to the license renewal of Peach Bottom Atomic Power Station, Units 2 and 3. The staff considered this RAI resolved.

Core Shroud - In addition to the implementation of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, Chemistry Control Program, and BWR Vessel Internals Program, the applicant committed to implement the inspection guidelines of BWRVIP-76 "Boiling Water Reactor Core Shroud Inspection and Flaw Evaluation Guidelines." The staff's review of this report is not complete. The applicant proposed to evaluate the staff SER and complete SER action items. The staff requested that the applicant make a commitment to follow all the requirements and limitations that may be specified in the staff SE on the BWRVIP-76 report. The staff found that, by implementing a proper chemistry program as dictated by the Chemistry Control Program, the oxidizing nature of RCS water can be controlled and, thereby, the corrosion of the core shroud can be controlled. In addition, implementation of the Inservice Inspection Program mandated by ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and additional inspection guidelines required by BWRVIP-76, will adequately identify any cracking in a timely manner so that proper repair and other mitigation techniques can be implemented to restore the function of the core shroud. Since the implementation of these additional guidelines and AMPs is consistent with the GALL AMP XI.M9, and Table IV.B1.1-a through IV.B1.1-g, the staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

In RAI 4.2.4-1(B), dated December 1, 2004, the staff stated that in LRA Section 4.2.4, the applicant stated that the maximum 54 EFPY fluence at the inside surface of the core shroud is 5.34×10^{21} n/cm^2 (E > 1.0 MeV). Therefore, the staff requested that the applicant address the aging effect due to IASCC in the core shroud component.

In its response, by letter January 31, 2005, the applicant stated that the core shrouds are classified as "Category C," based on the core shroud classification criteria contained in Appendix B of the BWR Vessel Internals Program. The BWR Vessel Internals Program requires inspection of core shroud welds in accordance with "Category C" core shroud inspection requirements contained in BWRVIP-76. The staff reviewed this response and accepted it (pending the approval of the BWRVIP-76 report) because implementation of the BWR Vessel Internals Program and the Chemistry Control Program would adequately manage the aging effect due to IASCC in the core shroud components and is consistent with GALL AMP XI.M9 and XI.M2.

Core Plate - The applicant proposed to implement the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, Chemistry Control Program, and BWR Vessel Internals Program. The BWR Vessel Internals Program in turn invokes the inspection guidelines of the BWRVIP-25, "Boiling Water Reactor Core Plate Inspection and Flaw Evaluation Guidelines," which has been approved by the staff. The staff found that by implementing a proper chemistry program as dictated by the Chemistry Control Program, the oxidizing nature of the RCS water can be controlled and, thereby, the corrosion of the core plate can be controlled. In addition, implementation of the Inservice Inspection Program mandated by the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and additional inspection guidelines required by BWRVIP-25, will adequately identify any cracking in a timely manner so that proper repair and other mitigation techniques can be implemented to restore the function of the core plate. Since the implementation of these additional guidelines and AMPs is consistent with the GALL AMP XI.M9, and Table IV.B1.1-a through IV.B1.1-g, the staff found that the applicant had demonstrated that the effects of aging will be adequately managed 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).

In-core Instrumentation Dry Tubes and Guide Tubes - In addition to the implementation of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, the Chemistry Control Program, and BWR Vessel Internals Program, the applicant committed to invoke the inspection guidelines specified in BWRVIP-47, "Boiling Water Reactor Lower Plenum Inspection and Flaw Evaluation Guidelines," which has been approved by the staff. The staff found that by implementing a proper chemistry program as dictated by the Chemistry Control Program, the oxidizing nature of the RCS water can be controlled and, thereby, the corrosion of the in-core instrumentation dry tubes and guide tubes can be controlled. In addition, implementation of the Inservice Inspection Program mandated by the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and additional inspection guidelines required by BWRVIP-47, will adequately identify any cracking in a timely manner, so that proper repair and other mitigation techniques can be implemented to restore the function of the in-core instrumentation dry tubes and guide tubes. Since the implementation of these additional guidelines and AMPs is consistent with the GALL Report, the staff found that the applicant has demonstrated that the effects of aging will be adequately managed 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).

4.7.6.3 UFSAR Supplement

Section LRA A.3.5.5 includes the following UFSAR Supplement summary description for the TLAA on IASCC of the RV internals.

> Austenitic stainless steel RV internal components exposed to a neutron fluence greater than 5 x 10^{20} n/cm ^{2}(E > 1 MeV) are considered susceptible to irradiation assisted stress corrosion cracking (IASCC) in the BWR environment. Fluence calculations have been performed for the RV and internals. Four components have been identified as being susceptible to IASCC for the period of extended operation: (1) Top Guide; (2) Shroud; (3) Core Plate and (4) In-core Instrumentation Dry Tubes and Guide Tubes. Three components (top guide, shroud and in-core instrumentation dry tubes and guide tubes) have been evaluated by the BWRVIP, as described in the Inspection and Evaluation Guidelines for each component: BWRVIP-26 (Top Guide), BWRVIP-76 (Shroud), and BWRVIP-47 (incore instrumentation dry tubes and guide tubes). BFN implements the BWRVIP recommendations. The Chemistry Program and the BWR Vessel Internals Program will be used to manage the core plate.

The applicant's UFSAR supplement summary description for the TLAA on IASCC of the RV internals appropriately describes the implementation of relevant AMPs that would enable the applicant to effectively manage this aging effect. The staff, however, requires that the applicant revise the UFSAR supplement to indicate that the inspection guidelines of the BWRVIP-25 "Boiling Water Reactor Core Plate Inspection and Flaw Evaluation Guidelines," will be implemented to effectively manage the aging effect on core plate. The applicant, in its response dated May 25, 2005, revised LRA Section A 3.5.5 of the UFSAR supplement summary description which describes that the inspection guidelines that are specified in the BWRVIP-25 report will be implemented for managing the aging effect on core plate. The staff considered this acceptable.

4.7.6.4 Conclusion

The staff reviewed the applicant's TLAA on IASCC of the RV internals, as summarized in LRA Section 4.7.6, and determined that, except for the top guide grid beams, the applicant appropriately describes that by implementing the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, the Chemistry Control Program and BWR Vessel Internals Program, and relevant additional BWRVIP guidelines related to RV internal components, the aging effect due to IASCC will be adequately managed for the period of extended operation. The license renewal action items related to the implementation of the BWRVIP-25, BWRVIP-26, and BWRVIP-47 guidelines are discussed in SER Section 3.1 on AMR. In addition, the staff believes that the implementation of these additional guidelines and AMPs is consistent with the GALL AMP XI.M9, and Table IV.B1. Therefore, the staff concluded that the applicant had demonstrated that the effects of aging due to IASCC in the RV internals with the exception of the top guide grid beams, as stated above, will be adequately managed 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(c)(1)(iii).

4.7.7 Stress Relaxation of the Core Plate Hold-Down Bolts

4.7.7.1 Summary of Technical Information in the Application

The core plate hold-down bolts connecting the core plate to core shroud are initially preloaded during installation. These bolts are subject to stress relaxation due to thermal and irradiation effects. The loss of preload over time due to stress relaxation is considered a TLAA and evaluated accordingly. In the LRA, the applicant stated that it evaluated the loss of preload of the core plate hold-down bolts for the 40-year lifetime and concluded that all core plate hold-down bolts will maintain some preload throughout the life of the plant. This conclusion was based on an analysis of loss of preload for core plate hold-down bolts, referenced in BWRVIP-25, Appendix B, "BWR Core Plate Inspection and Flaw Evaluation Guidelines." (Reference 5). For the 60-year lifetime, the applicant estimated the expected loss of preload to be less than 20 percent. With this loss of preload, the applicant stated that the core plate will maintain sufficiently high preload at the end of the period of extended operation to prevent sliding under both normal and accident conditions. Based on this assumption, the applicant concluded that the loss of preload is acceptable for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.7.7.2 Staff Evaluation

To complete its review, the staff requested additional information regarding the data and analyses that were used to determine that the loss of preload due to stress relaxation at the end of the period of extended operation would be less than 20 percent. The staff also requested that the applicant show that the hold-down bolts would meet the required ASME Code Section III stress acceptance criteria at the end of the period of extended operation.

In RAI 4.7.7-1, dated March 3, 2005, the staff requested that the applicant demonstrate the applicability of BWRVIP-25, (Reference 5) Appendix A, core plate hold-down bolt analysis to the BFN units, based on the configuration and the geometry of the BFN core plate hold-down bolts and the reactor environment (temperature and neutron fluence) assumed in the report.

In its response, by letter dated May 31, 2005, the applicant stated that the BFN core plate corresponds to that in BWRVIP-25, Figure 2-4, and that BFN was specifically considered in the original BWRVIP-25 evaluation, incorporating typical values of temperature and fluence. An analysis was initially performed for a 40-year plant life, and subsequently for a 60-year plant life, as discussed in BWRVIP-25, Appendix B, paragraph B.4, which addressed license renewal. This initial BWRVIP-25 based analysis assumed 20 percent hold-down bolt preload relaxation over a 60-year plant life.

To address EPU conditions in conjunction with license renewal, the applicant stated that a plant-specific calculation was performed for the BFN units. This calculation was based on the BFN fluence calculation which was performed considering EPU operating power and time conditions. The applicant stated that the applicable maximum bolt fluence was determined to be 5×10^{19} n/cm^2 (E > 1MeV) at the end of the 60-year plant life. The resulting hold-down bolt load relaxation was determined to be 15 percent, based on General Electric Nuclear Energy (GENE) design documents.

The staff reviewed this response and concluded that additional information was needed to complete its evaluation. The additional information was requested in the follow-up to RAI 4.7.7-1 which is discussed later.

In RAI 4.7.7-2, dated March 3, 2005, the staff requested that the applicant:

(a) Identify the temperature of the bolts during the normal operation and the projected bolt neutron fluence at the end of the period of extended operation.

(b) Explain how it was determined that the effects of temperature and neutron fluence result in a 20 percent loss of preload.

(c) Provide a detailed description of the methodology and data used at BFN to perform the analysis as described in (b), and include the basis for the relaxation curves.

In its response to RAI 4.7.7-2, dated May 31, 2005, the applicant responded as follows:

(a) The normal operating temperature for the core plate bolts is 550 °F. For the BFN units, the projected fluence was determined to be 5 x 10^{19} n/cm^2 (E > 1MeV) for a 60-year lifetime, (assuming a 90 percent capacity factor) for the bolt at the peak radial location. The arrangement of the bolts around the periphery of the core plates assures that many of the bolts experience a significantly lower lifetime fluence.

(b) The plant-specific evaluation used GENE proprietary relaxation curves from a GENE material design document for irradiated stainless steel properties at 550 °F, that was developed in the1970s time frame. The document was based on a combination of GENE internal reports and industry data to evaluate bolt stress relaxation.

(c) The BFN calculation was performed based on the BFN-specific core plate geometry, fluence and temperature. The BFN fluence conditions and the expected bolt stress relaxation made use of either GENE methods or GENE design documents. In support of the relaxation value used in the calculations, the applicant provided relaxation vs. fluence data from BWRVIP-99, "Crack Growth Rates in Irradiated Stainless Steels In BWR Internal Components." (Reference 6). This data was developed for type 316 stainless steel material, based on data found in the literature. The applicant justified the application to type 304 stainless steel material on the basis that the two commercial material alloys have the same single-phase austenitic microstructure and crystal structure, with no precipitates present in either alloy, and the mechanical properties are essentially identical at 550 °F.

The staff reviewed the information in this response and concluded that additional information was needed to complete its evaluation. The additional information was requested in RAI 4.7.7-3 through 4.7.7-7 by letter dated June 22, 2005.

In RAI 4.7.7-3, dated June 22, 2005, the staff requested that the applicant provide the data that GENE used to develop the stress relaxation curves and explain how this data was utilized to establish the curves.

In its response, by letter dated June 29, 2005, the applicant presented a mean design curve developed by GENE using stress relaxation values of irradiated stainless steel materials. The data was obtained from measurements made on springs and bent-beam specimens.

The staff's review of the applicant's response to RAI-4.7.7-3 is included in the staff's review of RAI 4.7.7-4.

In RAI 4.7.7-4, dated June 22, 3005, the staff stated that the applicant referenced BWRVIP-99 report, Figure 7-13, which shows data and modeling projections for stress relaxation versus fluence values measured in displacements per atom (dpa) for 20 percent cold-worked type 316 stainless steel material. The staff requested that the applicant provide an explanation justifying the applicability of the Type 316 stainless steel data to the Type 304 stainless steel core plate hold-down bolts at the BFN units.

In its response, by letter dated June 29, 2005, the applicant stated that the stress relaxation property of irradiated stainless steel materials does not vary with change in chemical composition. To support this claim, the applicant provided Halden (in-situ tests in the Halden reactor) data which show that there is very small variation in stress relaxation values between Type 304, 316, and 348 stainless steel specimens. The stress relaxation data were obtained from specimens that were exposed to 4.4 to 6 x 10^{20} n/cm^2 (E > 1MeV) in 288 °C water. These neutron fluence values are nearly 10 times higher than that of BFN core plate hold down bolts; therefore, stress relaxation values for the BFN bolts will be less than the values that are presented in the data. The applicant compared the Halden data with GENE data and concluded that for a given neutron fluence value the corresponding stress relaxation value that is obtained from the GENE data is more conservative than that from the Halden data.

The staff reviewed the applicant's responses to RAIs 4.7.7-3 and 4.7.7-4 and concluded that supporting data to the applicant's claim that the variation in chemical composition of stainless steel materials has very little effect on the stress relaxation of the irradiated stainless steel materials. Therefore, the staff concluded that the stress relaxation curves for the irradiated Type 316 stainless steel material can be applicable to irradiated Type 304 stainless steel materials. The staff reviewed the data in the applicant's response dated June 29, 2005, and found that for a given neutron fluence value the corresponding stress relaxation value obtained from GENE data is conservative and is acceptable.

In RAI 4.7.7-5, dated June 22, 2005, the staff requested that the applicant provide the dpa values for Type 304 core plate hold-down bolts that correspond to end-of-life fluence (54 EFPY) using appropriate model for the BFN units.

The staff's review of the applicant's response to RAI 4.7.7-5 is included in the staff's review of the follow-up to RAI 4.7.7-1.

In RAI 4.7.7-6, dated June 22, 2005, the staff requested that the applicant provide justification for the application of relaxation curves obtained based on data from torsion tests to axial relaxation in bolts.

In its response, by letter dated June 29, 2005, the applicant stated that the GENE stress relaxation data is obtained from test samples that include springs that represent torsional loading, and bent-beam specimens that represent tension loading. The applicant presented stress relaxation data that represented tension loading and another set representing shear loading, and they both exhibit similar behavior as GENE stress relaxation curve, but at a lower value. The data also indicated that the stress relaxation curve was not affected by the specimen or type of loading. Therefore, the applicant concluded that the stress relaxation values that are presented are applicable for torsional and axial loadings.

The staff reviewed the applicant's response and concluded that the stress relaxation curves and the applicant's presented data on the stress relaxation values are applicable for torsional and axial loadings.

In RAI 4.7.7-7, dated June 22, 2005, the staff requested that the applicant provide the calculations referenced in Appendix B of BWRVIP-25 so that it can evaluate the stress relaxation of the core plate hold-down bolts for the end-of-license fluence (54 EFPY) for the BFN units.

In its response to RAIs 4.7.7-5 and 4.7.7-7, dated June 29, 2005, the applicant provided a proprietary response in reply to the staff RAIs (ADAMS Accession No: ML052150189). In the response the applicant stated that a plant-specific calculation was performed for the BFN units using a neutron fluence value of 5×10^{19} n/cm^2 (E > 1MeV) which is equivalent to 0.07 displacement damage (measured as dpa) at the peak fluence location. The dpa value is calculated based on the calculated fast fluence and an effective dpa cross section (E > 1 MeV) of approximately 1380 barns for steel. The GENE stress relaxation value for this neutron fluence and dpa values is 15 percent, which is a conservative value, falls within the bounding value of 20 percent that was specified in the BWRVIP-25 report. The staff's review of the applicant's response to RAI-4.7.7-5 is included in the staff's review of the follow-up to RAI 4.7.7-1.

The staff reviewed the information in the responses to RAI 4.7.7-3 through 4.7.7-7, and concluded that additional information was needed to complete its evaluation. The additional information was requested in follow-up to RAI 4.7.7-1 and 4.7.7-2 by letter dated August 2, 2005.

In the follow-up to RAI 4.7.7-1, dated August 2, 2005, the staff indicated that in the data provided by TVA in its submittal dated June 29, 2005, the applicant compared the stress relaxation for the BFN core plate hold-down bolts to the stress relaxation data derived from springs and stainless steel bent beam specimens. The staff requested that the applicant provide information regarding the values of neutron flux and temperature at which the bent beam and spring test specimens were exposed, and compare them to the neutron flux and temperature values of the BFN core plate hold-down bolts. If these neutron flux and temperature values are different from those for the spring and bent beam specimens, the staff requested that the applicant evaluate the impact of these differences on the predicted stress relaxation values of the BFN core plate hold-down bolts.

In its response to the follow-up to RAI 4.7.7-1, dated September 6, 2005, the applicant addressed the effects of temperature and neutron flux on the stress relaxation values at which the irradiation tests were conducted. In its response, the applicant stated that given the large range of higher flux for which the properties are the same, the impact of the lower flux to which the bolts are exposed is viewed to be negligible. In support, the applicant stated that the temperature and fluxes associated with the design basis data are appropriate for use in predicting stress relaxation in the BFN core plate bolts. The test data was all generated at temperatures from 530 °F to 600 °F and, therefore, is fully representative of BWR operating conditions. The nuclear spectrum is also similar to that for the core plate bolt region. While the test data was generated at higher fluxes than present in the core plate region, the applicability of the data for use in the core plate bolt assessment is supported by mechanistic understanding as well as component test results.

Since the temperatures at which the majority of the irradiation tests were conducted represent the temperatures of the core plate hold-down bolts at the BFN units, the applicant claimed that the stress relaxation data that was provided by GENE would be representative of the BFN core plate hold-down bolts. The applicant further reiterated that the tests conducted at a neutron flux value higher than that of the core plate hold down bolts can be applicable for evaluating the stress relaxation data for the BFN's core plate hold-down bolts.

The staff reviewed the applicant's responses to the aforementioned RAI and determined that the applicant's justification for using the GENE methodology in the applicant's response in developing the stress relaxation curves is acceptable for the following reasons. GENE developed the stress relaxation curve for irradiated austenitic stainless steel materials at temperatures equivalent to the BWR normal operating temperatures and at a neutron fluence value equivalent to 54 EFPY for the BFN units. The stress relaxation data demonstrates that the impact of test temperature and neutron flux values for the test samples are not significant. The stress relaxation curve indicates that the relaxation value for the neutron fluence equivalent to 54 EFPY at the BFN units is 15 percent. The staff concluded that the stress relaxation value of 15 percent is a conservative value and falls within the bounding value of 20 percent that was provided in the generic analysis of the staff-approved BWRVIP-25 report.

In the follow-up to RAI 4.7.7-2, dated August 2, 2005, the staff requested that the applicant show that, under design basis accident condition loading stated in Scenario 3 of BWRVIP-25, Appendix A, the axial and bending stresses for the mean and highest loaded hold-down bolts will not exceed the ASME Section III allowable stresses for P_m (primary membrane) and $P_m + P_b$ (primary membrane plus bending) as a result of a 20 percent reduction in the specified bolt pre-load. The staff also requested that the applicant state clearly the assumptions on which the analysis was based.

In its response to the follow-up RAI 4.7.7-2, dated September 6, 2005, the applicant indicated that the BFN current licensing basis states that: "Two considerations important to the core support evaluation are sliding of the core support and buckling of the supporting beams. Evaluations have determined that the core support will not slide under postulated accident conditions with preload on the hold-down bolts. Additional resistance to sliding is provided by aligning pins which further stabilize the core support." The applicant also provided a (proprietary) stress calculation of the hold-down bolts which demonstrated that the axial and bending stresses met the stress criteria in BWRVIP-25, Appendix A.

The staff reviewed the applicant's response and identified the following concerns:

- The analysis does not correspond to the plant-specific core plate/hold-down bolt analysis recommended in Appendix A of BWRVIP-25. The applicant's analysis assumes that the core plate is rigid. The recommended approach is based on an elastic finite element analysis of the core plate/hold-down bolts.
- The applicant selected friction due to hold-down bolt preload as the means to prevent sliding of the core plate under horizontal loading. BWRVIP-25 recommends the

installation of wedges to prevent sliding; it does not recommend high preload to induce sufficient friction to prevent sliding. No basis for this choice was provided.

- The analysis is based on stipulated high preload (including 20 percent relaxation) of the hold-down bolts and a high static coefficient of friction to prevent sliding of the core plate under accident basis horizontal loading. No basis was provided for this high static coefficient of friction. Based on a comparison with values found in the literature, the coefficient of friction used in the analysis is similar to that stipulated as friction between dry metal surfaces. This value is not considered applicable to friction between the core plate and its shroud support, which are immersed in a BWR hot water environment. The staff believes that the static coefficient of friction in this environment is considerably lower, similar to that for friction between lubricated metal surfaces.

- As a result of the assumed rigidity of the core plate and high coefficient of static friction, and leading to the prevention of sliding under horizontal loading, the only stress state in the hold-down bolts is axial, caused by the bolt pre-load and vertical loading on the core plate. The core plate/hold-down bolt analysis in BWRVIP-25, Appendix A is based on relatively low bolt pre-load and no friction. As a result, the core plate is restrained from sliding by the hold-down bolts only, which induces bending stresses in the bolts. A low coefficient of friction may show that core plate sliding under the horizontal loading may not be prevented, thus inducing bending stresses in the hold-down bolts, in addition to the axial stresses.

- BWRVIP-25 indicates that "of special interest is the amount of bending induced in the bolts when the core plate bows upward, or when load from the beams is no longer transferred to the rim." This effect cannot be determined from the applicant's analysis if the core plate is assumed rigid.

- The stipulated hold-down bolt preload in the applicant's analysis is considerably larger that the preload in the analysis in BWRVIP-25, Appendix A. The effect of this preload on the structural integrity of the core plate was not evaluated.

- The finite element analysis of the core plate/hold-down bolts in Appendix A shows that the axial and transverse bolt loads vary around the circumference of the core plate. The axial loads in the highest loaded bolts are about twice the mean of the axial bolt loads. The applicant's analysis, based on a rigid plate analysis, shows that all bolts are uniformly loaded in tension and does not reflect the true distribution of the bolt loads.

- BWRVIP-25 specifies the design basis accident loads that should be considered in a plant-specific analysis. It is not clear that all applicable loads were considered in the applicant's analysis.

Based on these concerns, the staff concluded that the applicant did not provide reasonable assurance that the axial and bending stresses in the hold-down bolts will meet the ASME Section III primary stress limits as stated in BWRVIP-25, Appendix A, under the BFN plant-specific design basis accident loading and with 20 percent relaxation of hold-down bolt preload. This was, therefore, identified by the staff as Open Item 4.7.7.

Follow-up teleconferences with the applicant were held on October 14 and 18, 2005, to address the resolution of Open Item 4.7.7. This open item was included as one of four open items in an interim evaluation by the Advisory Committee on Reactor Safeguards of BFN's license renewal application and in the NRC's draft Safety Evaluation Report. By letter dated October 31, 2005, the staff provided the applicant a summary and discussion of the teleconferences, in which the staff position on this open item was summarized. The letter summarized the staff's concerns, as follows:

The applicant did not use the staff-approved analysis that was used in BWRVIP-25 report for the BFN units. The methodology used in the BWRVIP-25 report is more conservative. For BFN units, the applicant used a less conservative methodology, such as using a high static coefficient of friction value to ensure prevention of sliding of the core plate which eliminated the bending stresses in the core plate hold-down bolts. The staff determined that the static coefficient of friction used by the applicant is not supported by the available information provided in the literature.

The staff also questioned whether the applicant had considered using wedges to prevent core plate sliding, and if the wedges are installed, the aging management of core plate hold-down bolts will not be considered a TLAA item. The applicant stated that this option was evaluated but it is costly to install wedges in each unit. This option was, therefore, withdrawn.

The staff identified and summarized the following concerns:

(1) The analysis is significantly different from the structural analysis in BWRVIP-25, and is not based on a finite element model of the core plate.

(2) It is not clear that all loads listed in BWRVIP-25, such as fuel lift load, were included in the analysis.

(3) The applicant selected friction due to high bolt preload (significantly larger than that specified in BWRVIP-25) as the means to prevent side motion of the core plate. BWRVIP-25 recommends the use of wedges to prevent side motion; it does not recommend high bolt preload and friction.

(4) The applicant analysis assumes a high static coefficient of dry friction as the mechanism to prevent side motion of the core plate. The staff questions the basis for this assumption for a core plate that is in a BWR water environment.

(5) BWRVIP-25, Appendix A, page 4-6 states that "of special interest is the amount of bending induced in the bolts when the core plate bows upward, or when load from the beams is no longer transferred to the rim." No such bending was evaluated in the applicant's analysis.

(6) The BWRVIP-25 structural analysis shows a variation of the axial forces in the hold-down bolts with location around the plate circumference, and that the axial force in the highest-loaded bolt is about twice the mean axial bolt load. The applicant analysis shows that all bolts are uniformly loaded in tension. This indicates that the highest stresses in the hold-down bolts have not been determined.

(7) The effect of the large bolt preloads on the structural integrity of the core plate was not evaluated.

The staff stated its position that, for the BFN units, the applicant should apply the staff-approved methodology that was used in the BWRVIP-25 report.

By letter dated November 16, 2005, the applicant stated in Enclosures 3 and 9 the following commitment for BFN for the core plate hold-down bolts:

The applicant will perform a BFN plant-specific analysis consistent with BWRVIP-25 to demonstrate that the core plate hold-down bolts can withstand normal, upset, emergency, and faulted loads, as applicable, considering the effects of stress relaxation until the end of the period of extended operation. The installed core plate configuration and bolt preload will be used for the plant-specific analysis. The analysis will use the plant-specific design basis loads and load combinations. The analysis will incorporate detailed flux/fluence analyses and improved stress relaxation correlations.

In accordance with BFN's CLB, the ASME Boiler and Pressure Code, Section III will be used as a guide in determining limiting stress intensities for reactor vessel internals. For those components for which stresses exceed the ASME Code allowables, either the elastic stability of the structure or the resulting deformation or displacement will be examined to determine if the safety design basis is satisfied. Appropriate corrective action will be taken if the plant-specific analysis does not satisfy the above criteria. The installation of core plate wedges to eliminate the need for the enhanced inspections of the core plate hold-down bolts as recommended by BWRVIP-25 is considered an acceptable corrective action.

The analysis or the corrective action taken to resolve this issue will be submitted to the staff for review two years prior to the period of extended operation.

The staff reviewed the applicant's commitment and concluded that it provides adequate assurance that the 60-year stress relaxation of the core plate hold-down bolts due to neutron exposure will not compromise the structural integrity and operability of the core plate to the end of the period of extended operation. Open Item 4.7.7 is, therefore, closed.

4.7.7.3 UFSAR Supplement

In a letter dated November 16, 2005, the applicant revised LRA Section A.3.5.6 to include the UFSAR supplement summary description for the TLAA on stress relaxation of the core plate hold-down bolts. On the basis of its review of the UFSAR supplement, the staff concluded that the summary description of the applicant's actions to address stress relaxation of the core plate hold-down bolts is adequate.

4.7.7.4 Conclusion

The staff concluded that the applicant's commitment to provide a revised analysis, two years prior to the start of the period of extended operation, regarding the stress relaxation TLAA of the core plate hold-down bolts, and that the analysis will remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii), is acceptable. The staff also concluded that the UFSAR supplement contains an appropriate summary description of this TLAA evaluation, sufficient to satisfy the requirements of 10 CFR 54.21(d).

4.7.8 Emergency Equipment Cooling Water Weld Flaw Evaluation

4.7.8.1 Summary of Technical Information in the Application

The TLAA of the EECW weld flaw evaluation is discussed in LRA Section 4.7.8. The applicant performed an analysis on 17 selected EECW system piping welds that have flaws. The original analysis included a stress evaluation of the flawed welds and fatigue crack growth calculations. The fatigue crack growth calculations were based on a conservative projection of 125 cycles for the remaining 25 years of the 40-year plant operating life based on five cycles per year. A cycle occurs when piping, including a subject weld, is removed from service then returned to service. This projection was derived from a very conservative estimate that each weld could experience up to five cycles per year. Review of the system function indicated that continuous operation is intended; however, some interruptions have been required for maintenance and other considerations. The applicant considers the fatigue crack growth portion of this analysis to be a TLAA.

As part of the LRA, the applicant found, based on current and recent plant operating experience, that it is unusual for any of these weld locations to experience more than one cycle in any given year. For the TLAA, the applicant assumed two cycles per year for the past and the foreseeable future. The cycle count of two cycles per year was applied to the 25 remaining operating years (projected when the calculations were performed), plus the 20 years of extended operation, resulting in a total cycle count of 90. This is less than the estimated cycle count used for qualification in the original calculation. Therefore, the applicant's position is that in accordance with 10 CFR 54.21(c)(1)(i), the analyses remain valid for the period of extended operation.

4.7.8.2 Staff Evaluation

As required by 10 CFR 54.21, applicants for license renewal must manage time-dependent aging effects by one of three acceptable methods:

1. Demonstrate that the TLAA on the aging effect for the current operation term remains valid for the period of extended operation.
2. Demonstrate that the TLAA on the aging effect for the current operation term and has been projected to the end of the period of extended operation.
3. Demonstrate that the effect of aging on the intended functions will be adequately managed for the period of extended operation.

In RAI 4.7.8-1, dated November 4, 2004, the staff requested that the applicant provide background information, including the code class, flaw inspection history, flaw sizes, and a description of any analysis including the method that was used to determine the flaw evaluation. In its response, by letter dated December 9, 2004, the applicant stated, in part:

> The flawed EECW welds are on BFN Seismic Class I piping that was designed to the B31.1-1967 Power Piping Code. For the BFN ASME Section XI program the welds are classified as ASME Class 3. Design conditions for the EECW system are 200 psig and 200°F. All of the related piping is qualified by analysis. This analysis satisfies BFN

Design Criteria No. BFN -50-C-7103 which supplements B31.1 analysis requirements by invoking plant condition dependent stress equations from ASME Section III, 1971 Edition, Summer 1973 Addenda. The stress analyses of the piping systems are also considered a Time Limited Aging Analysis (TLAA) which is addressed in the Application TLAA Section 4.3.3.

History of Discovery – A weld inspection program was initiated at BFN to determine the effects of MIC on the stainless steel piping girth butt welds in the EECW system, as a result of MIC discoveries at other plants. The inspection program was implemented by performing radiography on a sample of EECW piping welds. Radiography had not been performed on these welds during installation, as it was not required by the applicable code and specifications. The inspection identified defects in 33 welds. The 33 welds which had identified defects were reviewed by the ISI Level III interpreter and 27 of the welds were rejected because they did not meet ISI flaw acceptance standards. The ISI Level III interpreter determined that the other welds did meet flaw acceptance standards.

Analysis Performed – Two analyses were performed in association with the qualification of the remaining 27 EECW welds with welding defects.

The applicant performed a bounding fracture mechanics analysis for the scope of stainless steel EECW pipe sizes encompassing the 27 welds that had been rejected based on ASME Section XI acceptance standards. Of the 27 welds, 10 were found to be acceptable using the bounding fracture mechanics analysis. The remaining 17 welds are the subject of the TLAA.

For the 17 welds identified in LRA Section 4.7.8, the applicant indicated that a location-specific fracture mechanics analysis was performed. The weld-specific analysis applied essentially the same approach and considerations as the bounding analysis except that location-specific stresses determined for ASME Code Section III, Subsection NC-3652, Equations 9 and 10 in the piping analyses of record were used to calculate both the ASME Code Section XI allowable flaw size and the fatigue crack growth due to cyclic load for the 25 years remaining in the plant life. The applicant found that for the controlling location (i.e., maximum thermal stress) in each pipe size applicable to the 17 welds, fatigue crack growth for the 25-year period was insignificant. Although the staff did not perform a detailed review of the applicant's analysis, the staff found the applicant's approach acceptable. The remaining issue is whether the applicant's demonstration that the TLAA on the aging effect for the current operation term remains valid for the period of extended operation.

The applicant stated in its LRA that, based on current and recent plant experience, it is unusual for any of these weld locations to experience more that one cycle in any given year.

The applicant stated that review of the EECW system indicates that continuous operation is intended; however, some interruptions have been required for maintenance and other considerations. Through an informal request on January 31, 2005, the staff requested the applicant to provide the following information as a follow-up to RAI 4.7.8: (a) Based on the design function of the EECW system, discuss when and at what frequency would the system be shut down; (b) Based on the design function and the total past history, discuss whether the number of cycles in the fatigue evaluation bound the number of cycles projected for the period of extended operation; (c) Describe events, and the frequency that they have occurred, that resulted in system operational interruptions; and (d) Should the EECW system experience more cycles than is bounded by the applicant's analysis, discuss any plant procedures in place to identify this condition.

The applicant responded by letter on March 2, 2005, and provided the following as a follow up to RAI 4.7.8:

> The EECW system is intended to be in a continuous standby condition (i.e. under pressure-minimum flow) in both shutdown and operating plant modes. As currently designed, sections of this system may be isolated and depressurized for routine maintenance or repair. Based on operating history and future (anticipated operations) a total of 125 full pressure cycles (0 psig to design operating pressure) was selected as a conservative measure to ensure the number of fatigue cycles would not be exceeded. The preventative maintenance work orders scheduled on this system are of a periodicity of no less than 96 weeks (almost 2 years) and unless unexpected repairs are required, the system would not need to be depressurized. Using a conservatism of a little over 2 times in a year makes sense for it would be very unlikely for the same Section of the EECW system to be shutdown [sic] > 2 times in a year. Please review preventative maintenance scheduled items on [the] following page [Not included in this evaluation. See March 2, 2005 letter]. An administrative tracking system will be developed and used to ensure that the 125 fatigue cycles will not be exceeded.

Based on operating history and anticipated future operations coupled with the applicant's commitment to develop an administrative tracking system to ensure that the EECW system does not exceed the applicant's 125 full pressure cycles, the staff concluded that the EECW weld flaw evaluation is valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i) and is, therefore, acceptable.

4.7.8.3 UFSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include a UFSAR supplement summary description of the "programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation." The applicant provided a UFSAR supplement summary description of EECW weld flaw evaluation in LRA Section A.3.5.7. On the basis of its review, and the responses to the staff's RAIs, the staff concluded that the UFSAR supplement summary adequately describes the TLAA on EECW weld flaw evaluation and is, therefore, acceptable.

4.7.8.4 Conclusion

The staff reviewed the applicant's TLAA on EECW weld flaw evaluation, as summarized in LRA Section 4.7.8, including information submitted in response to the staff's RAIs, and determined that the effects of EECW weld flaw evaluation will be adequately managed. Therefore, the staff concluded that the applicant has demonstrated that the effects of EECW weld flaw evaluation will be adequately managed 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(c)(1)(iii).

4.8 Conclusion for Time-Limited Aging Analyses

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concluded that the applicant has provided an adequate list of TLAAs, as defined in 10 CFR 54.3. Further, the staff concluded that the applicant demonstrated that (1) the TLAAs will remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i); (2) the TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii); or (3) that the aging effects will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). The staff also reviewed the UFSAR supplement for the TLAAs and found that the UFSAR supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concluded that no plant-specific exemptions are in effect that are based on TLAAs, pursuant to 10 CFR 54.21(c)(2).

With regard to these matters, the staff concluded that there is reasonable assurance that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB, and that any changes made to the CLB, in order to comply with 10 CFR 54.29(a), are in accordance with the Atomic Energy Act of 1954, as amended, and the NRC's regulations.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS[1]

In accordance with Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), the Advisory Committee on Reactor Safeguards (ACRS) will review the license renewal application (LRA) for the Browns Ferry Nuclear (BFN) Units 1, 2, and 3. The ACRS Subcommittee on Plant License Renewal will continue its detailed review of the LRA after this safety evaluation report (SER) is issued. The applicant and staff from the U.S. Nuclear Regulatory Commission (the staff) will meet with the subcommittee and the full committee to discuss issues associated with the review of the LRAs.

After the ACRS completes its review of the LRAs and the SER, the full committee will issue a report discussing the results of its review. An update to this SER will include the ACRS report. This update will also include the staff's response to any issues and concerns identified in the ACRS report.

[1] This section is revised. See BFN LRA SER Supplement 1.

SECTION 6

CONCLUSIONS[1]

The staff of the U.S. Nuclear Regulatory Commission (NRC or the Commission) reviewed the license renewal applications for the Browns Ferry Nuclear, Units 1, 2, and 3, in accordance with Commission regulations and NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated July 2001. Title 10, Section 54.29, of the *Code of Federal Regulations* (10 CFR 54.29) provides the standards for issuance of a renewed license.

On the basis of its evaluation of the license renewal applications, the NRC staff concluded that the requirements of 10 CFR 54.29(a) have been met and that all open items and confirmatory items have been resolved.

The staff notes that any requirements of Subpart A of 10 CFR Part 51 are documented in Supplement 21 to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Browns Ferry Nuclear, Units 1, 2, and 3, Final Report," dated June 23, 2005.

[1] This section is revised. See BFN LRA SER Supplement 1.

APPENDIX A
COMMITMENTS FOR LICENSE RENEWALS OF BFN UNITS 1, 2, AND 3[1]

During the review of the Browns Ferry Nuclear Plant (BFN) license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff, the applicant made commitments related to aging management programs (AMPs) to manage aging effects of structures and components (SCs) before the period of extended operation. The following tables list these commitments, along with the implementation schedules and the sources of the commitments.

- Table 1 lists those commitments that are not for a specific unit.
- Table 2 lists commitments that are specific to Unit 1.

Note that these tables also contain non-AMP commitments.

[1] This commitment table is revised. See BFN LRA SER Supplement 1

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
1. Accessible Non-Environmental Qualification Cables and Connections Inspection Program	Develop and implement new program.	A.1.1	Prior to the period of extended operation	• LRA Section B.2.1.1
2. Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program	Revise implementing documents for LPRM cable system aging to reference existing Technical Specification requirements and license renewal reference(s).	A.1.2	Prior to the period of extended operation	• LRA Section B.2.1.2 • Response to follow-up to RAI 2.5-2 dated March 2, 2005
	Develop and implement new program to manage IRM cable system aging.		Prior to the period of extended operation	• LRA Section B.2.1.2 • Response to follow-up to RAI 2.5-2 dated March 2, 2005
3. Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program	Develop and implement new program to manage the medium-voltage cables to the Residual Heat Removal Service Water pumps.	A.1.3	Prior to the period of extended operation	• LRA Section B.2.1.3 • Response to RAI 3.6-3(a) dated December 9, 2004 • Response to follow-up RAI 3.6-3 dated January 18, 2005
4. ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD Program	Revise implementing documents to include license renewal reference(s).	A.1.4	Prior to the period of extended operation	• LRA Section B.2.1.4

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
5. Chemistry Control Program	Revise implementing documents to include license renewal reference(s).	A.1.5	Prior to the period of extended operation	• LRA Section B.2.1.5
6. Reactor Head Closure Studs Program	Revise implementing documents to include license renewal reference(s).	A.1.6	Prior to the period of extended operation	• LRA Section B.2.1.6
7. Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program	Revise implementing documents to include license renewal reference(s).	A.1.7	Prior to the period of extended operation	• LRA Section B.2.1.7
8. Boiling Water Reactor Feedwater Nozzle Program	Revise implementing documents to include license renewal reference(s).	A.1.8	Prior to the period of extended operation	• LRA Section B.2.1.8
9. Boiling Water Reactor Control Rod Drive Return Line Nozzle Program	Revise implementing documents to include license renewal reference(s).	A.1.9	Prior to the period of extended operation	• LRA Section B.2.1.9
10 Boiling Water Reactor Stress Corrosion Cracking Program	Revise implementing documents to include license renewal reference(s).	A.1.10	Prior to the period of extended operation	• LRA Section B.2.1.10
11. Boiling Water Reactor Penetrations Program	Revise implementing documents to include license renewal reference(s).	A.1.11	Prior to the period of extended operation	• LRA Section B.2.1.11 • Enclosure 1 of TVA letter dated September 14, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
12. Boiling Water Reactor Vessel Internals Program	Revise implementing documents to include license renewal reference(s).	A.1.12	Prior to the period of extended operation	• LRA Section B.2.1.12
	Inspect the top guide beams		Prior to the period of extended operation	• Response to NRC Question (3) dated May 25, 2005
	Establish an aging management program for the steam dryers.		Two years before the first BFN unit enters the period of extended operation	• Response to RAI 3.1-1 dated January 31, 2005
	Enhance the Reactor Pressure Vessel Internals Inspection (RPVII) Units 1, 2, and 3 procedure to require visual inspection of the Access Hole Covers (AHCs) and inspection of the AHC welds.		Two years before the first BFN unit enters the period of extended operation	• Response to RAI B.2.1.12-1(C) dated January 31, 2005 • Response to NRC Question (7) dated May 25, 2005
	Implement the inspection of weld TS-2 (BWRVIP-41).		When inspection technique for weld TS-2 being developed by the BWRVIP Inspection Committee is available.	• Response to Question (12) dated May 25, 2005
13. Flow-Accelerated Corrosion Program	Revise implementing documents to include license renewal reference(s).	A.1.14	Prior to the period of extended operation	• LRA Section B.2.1.15
14. Bolting Integrity Program	Revise implementing documents to include license renewal reference(s).	A.1.15	Prior to the period of extended operation	• LRA Section B.2.1.16

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
15. Open-Cycle Cooling Water System Program	Revise implementing documents to include license renewal reference(s).	A.1.16	Prior to the period of extended operation	• LRA Section B.2.1.17
16. Closed-Cycle Cooling Water System Program	Revise implementing documents to include license renewal reference(s).	A.1.17	Prior to the period of extended operation	• LRA Section B.2.1.18
17. Inspection of Overhead Heavy Load and Light Load Handling Systems Program	Revise implementing documents to include license renewal reference(s).	A.1.18	Prior to the period of extended operation	• LRA Section B.2.1.20
18. Compressed Air Monitoring Program	Revise implementing documents to: • Include license renewal reference(s). • Incorporate guidelines in ASME OM-S/G-2000, Part 17; ANSI/ISA-S7.0.01-1996; and EPRI TR 108147	A.1.19	Prior to the period of extended operation	• LRA Section B.2.1.21
19. BWR Reactor Water Cleanup System Program	Revise implementing documents to include license renewal reference(s).	A.1.20	Prior to the period of extended operation	• LRA Section B.2.1.22
20. Fire Protection Program	Revise implementing documents to include license renewal reference(s).	A.1.21	Prior to the period of extended operation	• LRA Section B.2.1.23

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
21. Fire Water System Program	Revise implementing documents to: • Include license renewal reference(s). • Perform flow tests or non-intrusive examinations to identify evidence of loss of material due to corrosion.	A.1.22	Prior to the period of extended operation	• LRA Section B.2.1.24
	Perform sprinkler head inspections to ensure signs of degradation, such as corrosion, are detected in a timely manner.		Prior to exceeding the 50-year service life for any sprinkler	• LRA Section B.2.1.24
22. Aboveground Carbon Steel Tanks Program	Revise implementing documents to include license renewal reference(s).	A.1.23	Prior to the period of extended operation	• LRA Section B.2.1.26
23. Fuel Oil Chemistry Program	Revise implementing documents to include license renewal reference(s).	A.1.24	Prior to the period of extended operation	• LRA Section B.2.1.27 • Enclosure 1 of TVA letter dated September 14, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
24. Reactor Vessel Surveillance Program	Revise implementing documents to include license renewal reference(s).	A.1.25	Prior to the period of extended operation	• LRA Section B.2.1.28
	Enhance the Integrated Surveillance Program (ISP) per proposed BWRVIP-116.		Prior to the period of extended operation	• LRA Section B.2.1.28
	If the ISP is not approved two years prior to the commencement of the license renewal period, a plant-specific surveillance program for each BFN unit will be submitted to the NRC.		Two years prior to the commencement of the license renewal period	• Response to RAI B.2.1.28-1(A) dated January 31, 2005 • Response to Question (9) dated May 25, 2005
	Maintain Unit 1 and Unit 3 surveillance capsules (standby capsules) available to the ISP.		Unit 3 is ongoing Unit 1 will commence at restart	• Response to Question (10) dated May 25, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
25. One-Time Inspection Program	Develop and implement new program.	A.1.26	Prior to the period of extended operation	• LRA Section B.2.1.29
	Develop and submit procedure for NRC review.		At least two years prior to the expiration of the current operating license	• Response to Proposed Unresolved Item 3.0-4 LP dated May 27, 2005
	Perform a one-time inspection of the ASME equivalent Class MC supports in a submerged environment of the Units 2 and 3 Torus.		Prior to the period of extended operation	• Response to RAI B.2.1.33-2 dated January 18, 2005
	Perform a one-time inspection of the in-scope submerged concrete in one individual CCW pump bay of the Intake Pumping Station.		Prior to the period of extended operation	• Response to Question 359 dated October 8, 2004 • Response to RAI 3.5-16 dated April 5, 2005
	Perform ultrasonic thickness measurements of tank bottoms for those tanks specified in the Fuel Oil Chemistry Program (B.2.1.27) and the Aboveground Carbon Steel Tanks Program (B.2.1.26).		Prior to the period of extended operation	• Response to RAI 7.1.19-1 dated May 25, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
26. Selective Leaching of Materials Program	Develop and implement program.	A.1.27	Prior to the period of extended operation	• LRA Section B.2.1.30
27. Buried Piping and Tanks Inspection Program	Revise implementing documents to include license renewal reference(s).	A.1.28	Prior to the period of extended operation	• LRA Section B.2.1.31
	Add a trigger to the excavation permit document to require notification of engineering to perform a piping inspection when piping is excavated.		Complete	• NRC Inspection Report dated January 27, 2005
	Determine (via engineering evaluation) if sufficient inspections have been performed to draw conclusion regarding ability of underground coating to protect piping. If required, conduct a focused inspection to draw conclusion concerning the coating.		Within ten years after entering the period of extended operation	• Response to RAI 7.1.22-1 dated May 25, 2005
	Revise implementing documents to inspect buried piping when it is excavated.		Complete	• Response to RAI 7.1.22-1 dated May 25, 2005
28. ASME Section XI Subsection IWE Program	Revise implementing documents to include license renewal reference(s).	A.1.29	Prior to the period of extended operation	• LRA Section B.2.1.32

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
29. ASME Section XI Subsection IWF Program	Revise implementing documents to include license renewal reference(s).	A.1.30	Prior to the period of extended operation	• LRA Section B.2.1.33
	Enhance program to manage the aging effects of ASME equivalent Class MC supports.		Prior to the period of extended operation	• Response to Follow-up RAI B.2.1.33-1 dated May 31, 2005
30. 10 CFR 50 Appendix J Program	Revise implementing documents to include license renewal reference(s).	A.1.31	Prior to the period of extended operation	• LRA Section B.2.1.34
31. Masonry Wall Program	Revise implementing documents to include license renewal reference(s).	A.1.32	Prior to the period of extended operation	• LRA Section B.2.1.35
	Revise implementing procedures to clearly identify structures with masonry walls within scope and to clarify qualification requirements for personnel who perform masonry wall walkdowns.		Prior to the period of extended operation	• LRA Section B.2.1.35

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
32. Structures Monitoring Program	Revise implementing documents to include license renewal reference(s).	A.1.33	Prior to the period of extended operation	• LRA Section B.2.1.36
	Enhance procedures implementing the10 CFR 50.65 Maintenance Rule Program to identify all structures and structural components within scope.		Prior to the period of extended operation	• LRA Section B.2.1.36 • Response to GALL audit Question 173 dated October 8, 2004 • Response to GALL audit Question 357 dated October 8, 2004
	Enhance procedures implementing the 10 CFR 50.65 Maintenance Rule program sampling approach to include examinations of below-grade concrete when excavated.		Prior to the period of extended operation	• LRA Section B.2.1.36 • Response to GALL audit Question 285 dated October 8, 2004
	Enhance procedures implementing the 10 CFR 50.65 Maintenance Rule program to include the guidance provided in ACI 349.3R-96 Chapter 7.		Prior to the period of extended operation	• LRA Section B.2.1.36
	Enhance LCEI-CI-C9, Attachment 1, "Buried Piping Inspection Checklist," to include "Mechanical Penetration" as an inspection attribute.		Prior to entering the period of extended operation	• Response to GALL audit Question 285 dated October 8, 2004

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
33. Inspection of Water-Control Structures Program	Revise implementing documents to include license renewal reference(s).	A.1.34	Prior to the period of extended operation	• LRA Section B.2.1.37
	Revise implementing documents to identify required structures and structural components within the scope of license renewal.		Prior to the period of extended operation	• LRA Section B.2.1.37
	Revise implementing documents to include special inspections following the occurrence of large floods, earthquakes, tornadoes, and intense rainfall.		Prior to the period of extended operation	• LRA Section B.2.1.37
	Implement periodic monitoring of the raw service water in close proximity to the Intake Pumping Station for the requirements of an aggressive environment.		Prior to the period of extended operation	• Response to RAI 3.5-16 dated April 5, 2005
34. Environmental Qualification Program	Revise implementing documents to include license renewal reference(s).	A.1.35	Prior to the period of extended operation	• LRA Section B.3.1
35. Fatigue Monitoring Program	Implement enhanced Fatigue Monitoring Program using the EPRI-licensed FatiguePro® cycle counting and fatigue usage tracking computer program.	A.1.36	Prior to the period of extended operation	• LRA Section B.3.2
36. Systems Monitoring Program	Revise implementing documents to include license renewal reference(s).	A.2.1	Prior to the period of extended operation	• LRA Section B.2.1.39 • Enclosure 1 of TVA letter dated September 14, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
37. Bus Inspection Program	Develop and implement new program.	A.2.2	Prior to the period of extended operation	• LRA Section B.2.1.40 • Response to RAI 3.6-4 dated December 9, 2004
38. Diesel Starting Air Program	Revise implementing documents to include license renewal reference(s).	A.2.3	Prior to the period of extended operation	• LRA Section B.2.1.41
39. Time-Limited Aging Analysis: Reactor Vessel Thermal Limit Analyses: Operating Pressure-Temperature Limits (P-T)	Develop and submit revised P-T limits to the NRC for approval.	A.3.1.5	Prior to the period of extended operation	• LRA Section A.3.1.5 • LRA Section 4.2.5
40. Time-Limited Aging Analysis: Environmental Qualification of Electrical Equipment	Revise existing EQ program to cover the extended period of operation.	A.3.3	Prior to the period of extended operation	• LRA Section A.3.3 • LRA Section 4.4
41. Time-Limited Aging Analysis: Other Plant Specific Time-Limited Aging Analysis: Emergency Equipment Cooling Water Weld Flaw Evaluation	Implement an administrative tracking system to ensure limiting number of fatigue cycles will not be exceeded at the select EECW locations.	A.3.5.7	Prior to the period of extended operation	• LRA Section A.3.5.7 • Response to RAI 4.7.8 dated March 2, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
42. RAI 2.1-2,A-3	Identify additional piping segments and supports/equivalent anchors to be placed in scope.	N/A	Complete	• Response to RAI 2.1-2,A-3 dated September 3, 2004 • TVA response dated February 28, 2005
43. RAI 2.1-2,B	Implement Unit 1, 2, and 3 DCNs to qualify twelve temperature switches in the Turbine Building.	N/A	Prior to the period of extended operation	• Response to RAI 2.1-2,B dated September 3, 2004
44. RAI 2.1-2,C RHRSW tunnel	Include 24-inch Raw Cooling Water discharge piping located in the RHRSW tunnel in scope of license renewal.	N/A	Complete	• Response to RAI 2.1-2,C RHRSW Tunnel dated September 3, 2004 • TVA response dated January 31, 2005
45. RAI 2.1-2,C Intake Pumping Station	Revise 10 CFR 54.4(a)(2) Scoping Methodology document to address components located in the lower compartments of the Intake Pumping Station.	N/A	Prior to next annual update	• Response to RAI 2.1-2,C Intake Pumping Station dated September 3, 2004
46. Open Item OI 2.4-3	Perform one time confirmatory ultrasonic thickness (UT) measurements on a portion of the cylindrical section of the drywell on Units 2 and 3.	N/A	Prior to the period of extended operation	• Enclosures 1 and 9 of TVA letter dated November 16, 2005

TABLE 1: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (NON-UNIT SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
47. Open Item OI 4.7.7	Perform a BFN plant-specific analysis consistent with BWRVIP-25 to demonstrate that the core plate hold-down bolts can withstand required loads, considering the effects of stress relaxation until the end of the period of extended operation. Take appropriate corrective action if the analysis does not satisfy the specified criteria. Submit the analysis or the corrective action taken to resolve the core plate hold-down bolt issue to the NRC for review.	N/A	Two years prior to the period of extended operation	• Enclosures 3 and 9 of TVA letter dated November 16, 2005
48. Open Item from AMP Inspection on Inspection of RHRSW Piping	Perform a confirmatory inspection of the RHRSW pump pit supply piping. Include instructions in the CCW pump pit Preventive Maintenance Program to periodically inspect the sluice gate valves. Perform a confirmatory inspection of the seismic restraints in the RHRSW pump pit.	N/A	Prior to the period of extended operation	• Enclosures 4 and 9 of TVA letter dated November 16, 2005

TABLE 2: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (UNIT 1 SPECIFIC)

NOTE: This Table does not contain all of the same Item Numbers as contained in Table 1. While there is a one-to-one correlation of items with the same number, the same Item Numbers are not in both tables as explained below:

- For Item Numbers 1. through 49., only those Item Numbers that have a Unit 1 specific commitment are included in this table.
- Item Number 63. applies only to Unit 1.

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
2. Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program	Include Unit 1 High-Range Radiation Monitoring cables in the Environmental Qualification (EQ) Program.	A.1.2	Prior to Unit 1 restart	• Response to GALL audit Question 169 dated October 8, 2004
5. Chemistry Control Program	Include Unit 1 in the program.	A.1.5	Prior to Unit 1 restart	• LRA Section B.2.1.5
7. Boiling Water Reactor Vessel Inside Diameter Attachment Welds Program	Include Unit 1 in the program.	A.1.7	Prior to Unit 1 restart	• LRA Section B.2.1.7
8. Boiling Water Reactor Feedwater Nozzle Program	Upgrade Unit 1 operating procedures to decrease the magnitude and frequency of feedwater temperature fluctuations.	A.1.8	Prior to Unit 1 restart	• LRA Section B.2.1.8
10. Boiling Water Reactor Stress Corrosion Cracking Program	Include Unit 1 in the program.	A.1.10	Prior to Unit 1 restart	• LRA Section B.2.1.10 • Response to GALL audit Question 181 dated October 8, 2004

TABLE 2: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (UNIT 1 SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
11. Boiling Water Reactor Penetrations Program	Include Unit 1 in the program.	A.1.11	Prior to Unit 1 restart	• LRA Section B.2.1.11 • Response to GALL audit Question 194 dated October 8, 2004
12. Boiling Water Reactor Vessel Internals Program	Include Unit 1 in the program.	A.1.12	Prior to Unit 1 restart	• LRA Section B.2.1.12 • Response to Question (4b) dated May 25, 2005
13. Flow-Accelerated Corrosion Program	Include Unit 1 in the program.	A.1.14	Prior to Unit 1 restart	• LRA Section B.2.1.15 • Response to GALL audit Question 144 dated October 8, 2004
15. Open-Cycle Cooling Water System Program	Include Unit 1 in the program.	A.1.16	Prior to Unit 1 restart	• LRA Section B.2.1.17 • Response to GALL audit Question 144 dated October 8, 2004
16. Closed-Cycle Cooling Water System Program	Include Unit 1 in the program.	A.1.17	Prior to Unit 1 restart	• LRA Section B.2.1.18 • Response to GALL audit Question 144 dated October 8, 2004
18. Compressed Air Monitoring Program	Include Unit 1 in the program.	A.1.19	Prior to Unit 1 restart	• LRA Section B.2.1.21

TABLE 2: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (UNIT 1 SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
19. BWR Reactor Water Cleanup System Program	Include Unit 1 in the program.	A.1.20	Prior to Unit 1 restart	• LRA Section B.2.1.22 • LRA Section F.13
20. Fire Protection Program	Update the Fire Protection Report and to incorporate Unit 1 as an operating unit. Fully implement the program on Unit 1.	A.1.21	Prior to Unit 1 restart	• LRA Section B.2.1.23
21. Fire Water System Program	Update the Fire Protection Report and procedures to incorporate Unit 1 as an operating unit. Fully implement the program on Unit 1.	A.1.22	Prior to Unit 1 restart	• LRA Section B.2.1.24
24. Reactor Vessel Surveillance Program	Either include Unit 1 within the BWRVIP ISP, or submit for NRC approval a plant specific surveillance program that meets the requirements of 10 CFR 50 Appendix H for the period of extended operation.	A.1.25	Prior to the period of extended operation	• LRA Section B.2.1.28
	Ensure BWRVIP-86-A and BWRVIP-116 are revised to incorporate Unit 1, and submit to the NRC a license amendment request to implement the ISP for site-specific use for Unit 1.		Prior to the period of extended operation	• Response to RAI B.2.1.28-1 dated January 31, 2005
25. One-Time Inspection Program	Perform a one-time inspection of the ASME equivalent Class MC supports in a submerged environment of the Unit 1 Torus.	A.1.26	Prior to Unit 1 restart	• Response to RAI B.2.1.33-2(b) dated January 18, 2005
34. Environmental Qualification Program	Include Unit 1 in the program.	A.1.35	Prior to Unit 1 restart	• LRA Section B.3.1

TABLE 2: BFN COMMITMENT LIST ASSOCIATED WITH LRA APPENDIX A AGING MANAGEMENT PROGRAMS AND TLAAs (UNIT 1 SPECIFIC)

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
47. Open Item OI 2.4-3	Perform one time confirmatory UT measurements on the drywell vertical cylindrical area immediately below the drywell flange	N/A	Prior to Unit 1 restart	• Enclosures 1 and 9 or TVA letter dated November 16, 2005
49. Unit 1 Periodic Inspection Program	Develop and implement new program.	A.2.4	Prior to the period of extended operation	• Response to Proposed Unresolved Items 3.0-2 LP (1 & 2) and 3.0-3 LP dated May 27, 2005 • Enclosure 1 of TVA letter dated September 14, 2005
	Develop and submit implementing procedure(s) for NRC review.		At least two years prior to the period of extended operation	• Response to Proposed Unresolved Items 3.0-4 LP dated May 27, 2005
63. Response to NRC Questions Concerning RPV Internals	Replace all BFN Unit 1 dry tubes.	N/A	Prior to Unit 1 restart	• Response to Question (8) dated May 25, 2005
	Perform MSIP for Unit 1 Control Rod Drive Return Line Cap.		Prior to Unit 1 restart	• Response to Question (6) dated May 25, 2005
	Change the Unit 1 AHCs to bolted design.		Prior to Unit 1 restart	• Response to NRC Question (7) dated May 25, 2005

TABLE 3: UNIT 1 RESTART COMMITMENTS THAT ARE DISCUSSED IN LRA APPENDIX F

NOTE: See Note at the beginning of Table 2

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
50. Appendix F.1	Evaluate and modify, as required, main steam leakage path piping to ensure structural integrity.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
51. Appendix F.2	Implement Containment Atmosphere Dilution System modification.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
52. Appendix F.3	Revise Fire Protection Program to ensure compliance with 10 CFR 50 Appendix R. Revise Fire Protection Report per Unit 1 License Condition 2.C.13.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
53. Appendix F.4	Implement Environmental Qualification Program.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
54. Appendix F.5	Address GL 88-01, and make necessary plant modifications.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
55. Appendix F.6	BWRVIP Programs used for Units 2 and 3 will be used for Unit 1.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
56. Appendix F.7	Install ATWS features.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005

TABLE 3: UNIT 1 RESTART COMMITMENTS THAT ARE DISCUSSED IN LRA APPENDIX F

Item Number/Title	Commitment	LRA Appendix A (UFSAR)	Implementation Schedule	Source
57. Appendix F.8	Remove Reactor Vessel Head Spray piping in drywell, and seal the primary containment penetrations	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
58. Appendix F.9	Implement the Hardened Wetwell Vent modification.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
59. Appendix F.10	Cap Service Air and Demineralized Water Primary Containment Penetrations.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
60. Appendix F.11	Modify Auxiliary Decay Heat Removal System to serve Unit 1.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
61. Appendix F.12	Fully implement the Maintenance Rule Unit 1's temporary exemption ceases to be effective.	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005
62. Appendix F.13	Replace RWCU piping outside of primary containment with IGSCC resistant piping. Implement actions requested in GL 89-10 for RWCU	N/A	Prior to Unit 1 restart	• LRA Appendix F • TVA response dated January 31, 2005

APPENDIX B

CHRONOLOGY

This appendix contains a chronological listing of the routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and the Tennessee Valley Authority (TVA), and other correspondence regarding the NRC staff's reviews of the Browns Ferry Nuclear (BFN), Units 1, 2 and 3 (under Docket Numbers 50-259, 50-260 and 50-296) license renewal application (LRA).

July 12, 1984	TVA letter to NRC, in regards to NUREG 0737, Item II.K.3.28, "Qualification of ADS Accumulators"
July 24, 1985	NRC letter to TVA, "NUREG 0737, Item II.K.3.28, Qualification of ADS Accumulators"
March 1, 1988	TVA letter, R. Gridley to NRC, "Browns Ferry Nuclear Plant (BFN) - Anticipated Transients Without Scram (ATWS) Rule (10 CFR 50.62) - Plant Specific Design"
August 1, 1988	TVA letter to NRC, "Browns Ferry Nuclear Plant (BFN) - Response to Bulletin (sic) 88-01, NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping, dated January 25, 1988"
October 24, 1988	TVA letter, S. A. White to NRC, "Browns Ferry Nuclear Plan (BFN) Nuclear Performance Plan, Revision 2"
December 8, 1988	NRC letter to TVA, "Browns Ferry Nuclear Plant, Units 1, 2 and 3 - Appendix R Safe Shutdown System Analysis"
January 22, 1989	NRC letter to TVA, "Compliance with Rule 10 CFR 50.62 Relating to Alternate Rod Injection and Reactor Pump Trip Systems"
January 26, 1989	NRC letter to TVA, "Technical Specifications on Anticipated Transients Without Scram (ATWS) - Recirculation Pump Trip (RPT), Browns Ferry Nuclear Plants, Units 1, 2, and 3" (Accession No. ML020020476)
October 30, 1989	NRC letter to All Operating Licensees with Mark I Containments, "Installation of a Hardened Wetwell Vent (Generic Letter 89-16)," dated September 1, 1989. 2. TVA letter, M. J. Ray to NRC, "Response to Generic Letter 89-16, Installation of Hardened Wetwell Vent"
November 2, 1989	NRC letter to TVA, "Supplemental Safety Evaluation on Post-Fire Safe Shutdown Systems and Final Review of the National Fire Protection Association Code Deviations - Browns Ferry Nuclear Plant, Unit 2"

November 29, 1990	TVA letter, E. G. Wallace to NRC, "Browns Ferry Nuclear Plant (BFN) - Anticipated Transient Without Scram (ATWS) Response to NRC Followup Items Received During ATWS Inspection
January 23, 1991	NRC letter to TVA, "NUREG 1232, Volume 3, Supplement 2 Browns Ferry, Unit 2"
March 6, 1991	NRC letter to TVA, "Issuance of Amendment" (Accession No. ML020090226)
May 5, 1992	NRC letter to TVA, "Request for Additional Information to Review Compliance with NUREG 0737, Item II.E.4.2 and 10 CFR 50, Appendix J
December 28, 1992	TVA letter to NRC, "Browns Ferry Nuclear Plant – Unit 3 - Supplemental Response to Generic Letter (GL) 88-01, NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping"
March 31, 1993	NRC letter to TVA, "Fire Protection Program - Browns Ferry Nuclear Plant Units 1, 2 and 3"
December 3, 1993	NRC letter to TVA, "Browns Ferry Nuclear Plant Unit 3 - Safety Evaluation of Supplemental Response to Generic Letter 88-01"
January 2, 1995	NRC letter to TVA, "Browns Ferry Nuclear Plant Units 1 and 3, NUREG-0737, Item II.E.4.2, Containment Isolation Dependability"
November 2, 1995	NRC letter to TVA, "Safety Evaluation of Post-Fire Safe Shutdown Capability and Issuance of Technical Specification Amendments for the Browns Ferry Nuclear Plant Units 1, 2, and 3" (Accession No. ML020040025)
April 25, 1997	BWRVIP letter, C. Terry to B. Sheron (NRC), "BWR Utility Commitments to the BWRVIP"
August 9, 1999	NRC letter to TVA, "Issuance of Temporary Partial Exemption from 10 CFR 50.65, Browns Ferry Nuclear Plant, Unit 1" (Accession No. ML020040329)
November 25, 2002	NRC Meeting Summary, S.T. Hoffman, "Summary Of Meeting to Discuss Planned License Renewal Application" (Accession No. ML023300013)
June 2, 2003	NRC Meeting Summary, S.T. Hoffman, Summary Of Meeting To Discuss Planned License Renewal Application (Accession No. ML031540295)
October 30, 2003	NRC Meeting Summary, S.T. Hoffman, "Summary Of Meeting to Discuss Browns Ferry Units 1, 2, and 3 Planned License Renewal Application" (Accession No. ML033080369)

December 3, 2003	NRC letter to TVA, "Browns Ferry Nuclear Plant Unit 3 - Safety Evaluation of Supplemental Response to Generic Letter 88-01"
December 31, 2003	Letter from Mr. Mark. J. Burzynski, Tennessee Valley Authority (TVA) to the NRC, submitting the application for the renewal of the operating Licenses for Browns Ferry Nuclear Units 1,2, and 3 (Accession No. ML040060361)
January 7, 2004	Letter from P.T.Kuo, NRC, to J.A.Scalice,TVA forwarding the Notice of Receipt and Availability of the application for the renewal of the operating license for the BFN Units 1,2 and 3 (Accession No. ML040090370)
February 19, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC- Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - January 28, 2004 Meeting Follow-Up - Additional Information - Supplemental Information - Unit 1 Wet Lay-Up (Accession No. ML040510241)
March 4, 2004	Letter from P.T.Kuo, NRC to J. A. Scalice, TVA indicating acceptability and sufficiency for docketing and opportunity for a hearing regarding the application from Tennessee Valley Authority for renewal of the operating licenses for the BFN, units 1, 2, and 3 (Accession No. ML040650206)
March 25, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC stating use of the BFN license renewal boundary drawings to obtain scoping results (Accession No. ML040860596)
March 31, 2004	Letter from P.T.Kuo, NRC, to J.A.Scalice,TVA forwarding the review schedule for application for renewal of the operating licenses for the BFN Units 1,2 and 3 (Accession No. ML040910016)
May 4, 2004	In a memorandum (signed by Jimi Yerokum), NRC summarized the April 7, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041310015)
May 6, 2004	In a memorandum (signed by Jimi Yerokum), NRC summarized the March 24, 2004 and March 30, 2004 teleconferences between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041310029)
May 10, 2004	In a memorandum (signed by Jimi Yerokum), NRC summarized the April 14, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041310206)

May 27, 2004	Browns Ferry Nuclear Plant (BFN) Units 1, 2, and 3 - March 30-31, 2004 meeting follow-up-additional information for License Renewal Environmental Review
May 28, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC updating the LRA application sections 4.2 and 4.3 to reflect extended power uprate conditions (Accession No. ML041550393)
June 15, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the May 19, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041700550)
June 16, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the April 21, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041700505)
June 16, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the May 27, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) concerning activities on BFN units 1, 2 and 3 LRA. (Accession No. ML041700523)
June 18, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the May 5, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041700572)
June 23, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 3.5 of the LRA. (Accession No. ML041760076)
June 28, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the May 27, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041810168)
July 7, 2005	Response to Request for Additional Information (RAI) regarding severe accident mitigation alternatives for Browns Ferry Nuclear Plant, Units 1, 2, and 3

July 9, 2004	TVA letter to NRC, "Browns Ferry Nuclear Plant (BFN) Unit 1 - Technical Specification (TS) 436 - Increased Main Steam Isolation Valve (MSIV) Leakage Rate Limits and Exemption from 10 CFR 50, Appendix J" (Accession No. ML041980222)
July 10, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the June 16, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML041950508)
July 19, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the April 28, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042010388)
July 19, 2004	Letter from Mr. M.J.Burzynski, Tennessee Valley Authority (TVA) to the NRC regarding lay-up effects of Unit 1 Structures and Component Supports (Accession No. ML042040231)
July 21, 2004	TVA letter, T. E. Abney to NRC, "Browns Ferry Nuclear Plant (BFN) Unit 1 – Supplemental Response to Generic Letter 88-01, NRC Position on Intergranular Stress Corrosion Cracking in BWR Austenitic Stainless Steel Piping" (Accession No. ML042040274)
July 28, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the July 1, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042110485)
July 30, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 2.1 of the LRA. (Accession No. ML042120186)
August 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC detailed explanation of how the LRA application Bounds the BFN extended power uprate (EPU) submittals (Accession No. ML042180449)
August 5, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC update of application sections 4.2 and 4.3 to reflect extended power uprate conditions –supplemental information (Accession No. ML042220285)

August 23, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on sections 3.1, 3.2, 3.3, and 3.4 of the LRA. (Accession NO. ML042360590)
August 23, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on sections 2.3, 3.3, 4.4, B.2.0 of the LRA (Accession NO. ML042360762)
August 23, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the July 28, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042390497)
August 26, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the July 24, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042400550)
August 31, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the July 12, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042450211)
August 31, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on sections 2.1, 2.2, and 2.3 of the LRA. (Accession No. ML042450260)
September 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC NRC scoping and screening audit – request for additional information (RAI) (Accession No. ML042520374)
September 16, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the August 19, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042600522)
September 27, 2004	NRC letter to TVA, "Browns Ferry Nuclear Plant, Units 1, 2, and 3 — Issuance of Amendments Regarding Full- Scope Implementation of Alternative Source Term" (Accession No. ML042730028)

September 30, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC NRC scoping and screening audit –request for additional information (Accession No. ML042750259)
October 6, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on 2.3.1, 2.3.2, and 2.3.3 of the LRA. (Accession No. ML042860015)
October 8, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC NRC scoping and screening audit –request for additional information (Accession No. ML042870422)
October 8, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 2.3 of the LRA. (Accession No. ML042860051)
October 8, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC NRC scoping and screening staff audit at BFN – request for additional information (Accession No. ML042870428)
October 8, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on sections 2.3.2 and 2.3.3 of the LRA (Accessiion No. ML042860066)
October 12, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 3.3 of the LRA (Accession No. ML042860133)
October 15, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the September 15, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042920201)
October 18, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC NRC scoping and screening audit – request for additional information (Accession No. ML042930471)
October 19, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC – request for additional information - Sections 2.1, 2.2, and 2.3, related to the Scoping and Screening: Mechanical Systems (Accession No. ML042930931)

October 21, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the September 22, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML042990519)
October 22, 2004	In a memorandum (signed by Yoira Diaz-Sanabria), NRC summarized the August 18, 2004 teleconference between the NRC staff and Tennessee Valley Authority (TVA) regarding draft Request for Additional Information (D-RAI) concerning the staff's review of the LRA. (Accession No. ML043000040)
October 25, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - request for additional information on Appendix F (Accession No. ML043000149)
October 28, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Fire Protection Section Verbal Request on October 20, 2004 - Response to NRC Request for Additional Information (Accession No. ML043030434)
November 1, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 2.5 of the LRA (Accession No. ML043060492)
November 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) – Units 1, 2, and 3 License Renewal Application – Heating, Ventilation, and Cooling (HVAC) Systems Sections 2.3.2 and 2.3.3 – Request for Additional Information (RAI) - (Accession No. ML043090545)
November 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) – Units 1, 2, and 3 License Renewal Application – Reactor Systems Section 2.3.1, 2.3.2, and 2.3.3 – Request for Additional Information (Accession No. ML043100588)
November 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Auxiliary Systems Section 3.3 - Response to NRC Request for Additional Information (Accession No. ML043090343)
November 4, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on sections 3.1.2.4, B.2.1.13, and 4.7.8 of the LRA (Accession No. ML043090573)

November 4, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on section 3.6 of the LRA (Accession No. ML043090577)
November 18, 2004	Letter from Ram Subbaratnam, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Sections 3.2 and 3.4 of the LRA (Accession No. ML043270655)
December 1, 2004	Letter from Ram Subbaratnam, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Sections 3.1 of the LRA (Accession No. ML043360401)
December 1, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – electrical and instrument and control systems (I&C) systems section 2.5- Response to NRC Request for Additional Information (Accession No. ML043370173)
December 3, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Heating, Ventilation, and Cooling (HVAC) Systems Sections 2.3.2 and 2.3.3 - Response to NRC Request for Additional Information (Accession No. ML043380353)
December 7, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Chemistry Control Program, Section B.2.1.5 of the LRA (Accession No. ML043490336)
December 9, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Mechanical Systems Sections 3.1.2.4, B.2.1.13, and 4.7.3- Response to NRC Request for Additional Information (Accession No. ML043440080)
December 9, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Electrical and Instrument and Control Systems (I&C) Systems Section 3.6- Response to NRC Request for Additional Information (Accession No. ML043440226)
December 9, 2004	Letter from Ram Subbaratnam, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding status of staff review of the Browns Ferry Nuclear Plant Units 1, 2, and 3 License Renewal Application (Accession No. ML043490470)

December 10, 2004	Letter from Ram Subbaratnam, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2, and 3 license renewal application on Section 3.5 and B.2.1.34 of the LRA (Accession No. ML043500140)
December 13, 2004	Letter from Ram Subbaratnam, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on ASME Section XI Subsection IWF Program, Section B.2.1.33 of the LRA (Accession No. ML043500210)
December 14, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application Section 4.7.1 of the LRA (Accession No. ML043500508)
December 16, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Mechanical Systems Sections 3.2 and 3.4 - Response to NRC Request for Additional Information (Accession No. ML043520395)
December 16, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application Section 3.0 of the LRA (Accession No. ML043560502)
December 20, 2004	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 4.4-2 Mechanical and Environmental Qualifications - Response to NRC Request for Additional Information (Accession No. ML043550381)
December 20, 2004	Letter from Yoira Diaz-Sanabria, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Section 2.4 of the LRA (Accession No. ML043560382)
January 6, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections B.2.1.5 Chemistry Control Program - Response to NRC Request for Additional Information (Accession No. ML050070179)
January 7, 2005	Letter from Mr. M. D. Skaggs, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application - Meeting Summary and Plant Visit (ML050100180)

January 12, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 4.7.1 Reactor Building Crane Load Cycle - Response to NRC Request for Additional Information (Accession No. ML050130333)
January 18, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections B.2.1.33 ASME Section XI Subsection IWF Program - Response to NRC Request for Additional Information (Accession No. ML050180505)
January 18, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 2.5 and 3.6 Electrical and Instrument and Control - Response to NRC Request for Additional Information (Accession No. ML050180537)
January 20, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 3.1 Aging of Mechanical Systems During the Extended Outage - Response to NRC Request for Additional Information (Accession No. ML050210334)
January 24, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 2.4 - Response to NRC Request for Additional Information (Accession No. ML050250264)
January 25, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 4.4 - Response to NRC Request for Additional Information (Accession No. ML050260327)
January 27, 2005	Letter from Harold O. Christensen, NRC, to K. W. Singer, Tennessee Valley Authority (TVA) regarding Browns Ferry Nuclear Plant - Inspection Report 05000259/2004012, 05000260/2004012, and 05000296/2004012 (Accession No. ML050270022)
January 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Annual Update (Accession No. ML050310428)
January 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – The Integration of Unit 1 Restart and License Renewal Activities. Response to NRC Request for Additional Information (Accession No. ML050320137)

January 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 3.1, 4.2, and B.2.1 Reactor Vessel and Internals Mechanical Systems - Response to NRC Request for Additional Information (Accession No. ML050320145)
January 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 3.5, 4.7.4, and B.2.1.32 - Response to NRC Request for Additional Information (Accession No. ML050320149)
January 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 3 Unit 1 layup questions - Response to NRC Request for Additional Information (Accession No. ML050320208)
January 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Section 2.1, status of response to RAI 2.1-2, A.3 - Response to NRC Request for Additional Information (Accession No. ML050310442)
February 28, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 2.1, final status of response to RAI 2.1-2, A.3 - Response to NRC Request for Additional Information (Accession No. ML050600274)
February 28, 2005	Browns Ferry Nuclear Plant - Units 1, 2, and 3 License Renewal Application - LRA Section 3.5 - response to NRC request for follow-up question for RAI 3.5-7
March 2, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 2.5 and 4.7.8 - Response to NRC Request for Additional Information (Accession No. ML050620258)
March 3, 2005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Section 4.7.7 of the LRA (Accession No. ML050620592)
March 11, 2005	Letter from Yoira Diaz-Sanabria, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Sections 3.1.2.4 and 3.5 of the LRA (Accession No. ML050700309)

March 11, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 3.3 - Response to NRC Request for Additional Information (Accession No. ML050700463)
March 16, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 4.6.2 T-Quenchers within Reactor Vessel Vents and Drains System - Response to NRC Request for Additional Information (Accession No. ML050760230)
March 16, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 3.1.2.4 and 4.3 Reactor Coolant Pressure Boundary Bolting Clarifications - Response to NRC Request for Additional Information (Accession No. ML050770041)
March 25, 2005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) forwarding request for additional information for the review of the BFN units 1, 2 and 3 license renewal application on Section 2.4 and 3.5 of the LRA (Accession No. ML050840483)
April 5, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 7.2.5.2 ASME Equivalent Supports and Components - Response to NRC Request for Additional Information (Accession No. ML050950189)
April 5, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 3.1.2.4-7 and 3.5-16 AMR Small Bore Piping and Fittings and Submerged Reinforced Concrete - Response to NRC Request for Additional Information (Accession No. ML050950311)
April 8, 2005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) Forwarding Request for Additional Information for the Review of the BFN Units 1, 2, and 3 License Renewal Application on Section 2.3.3.21 (Accession No. ML050980086)
April 14, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 2.4 and 3.5 Radwaste and Service Building - Response to NRC Request for Additional Information (Accession No. ML051040164)
April 19, 005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Trip Report of staff visit to Browns Ferry Nuclear Units 1,2, and 3 on March 28, 29, 2005 (Accession No. ML051090488)

April 28, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 2.3.3.21 Reactor Water Cleanup System - Response to NRC Request for Additional Information (Accession No. ML051190272)
May 12, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 7.2.5.2 ASME Equivalent Supports and Components - Response to NRC Request for Additional Information (Accession No. ML051330038)
May 18, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 2.3 and 2.4 - Response to NRC Request for Additional Information (Accession No. ML051380504)
May 18, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 3.0-9 Unit 1 Layup Program - Response to NRC Request for Additional Information (Accession No. ML051390237)
May 19, 2005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Summary of teleconference with Tennessee Valley Authority (TVA) License Renewal Staff (Accession No. ML051400190)
May 24, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 2.3.3.21 Reactor Water Cleanup System - Response to NRC Request for Additional Information (Accession No. ML051440261)
May 24, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 3.3 Diesel Generator - Response to NRC Request for Additional Information (Accession No. ML051440779)
May 24, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 2.4, 3.5 and 4.7.4 - Response to NRC Request for Additional Information (Accession No. ML051450126)
May 25, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 7.1.19 and 7.1.22 GALL Audit - Response to NRC Request for Additional Information (Accession No. ML051460348)

May 25, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Sections 4.2.6, 4.2.7 and 4.7.6 Reactor Pressure Vessel Internals - Response to NRC Request for Additional Information (Accession No. ML051460354)
May 26, 2005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Summary of teleconference with Tennessee Valley Authority (TVA) License Renewal Staff (Accession No. ML051460418)
May 27, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 3.0 Unit 1 Layup Program - Response to NRC Request for Additional Information (Accession No. ML051470354)
May 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 2.1.2 and 2.3.4.4 Secondary Containment and Main Steam System - Response to NRC Request for Additional Information (Accession No. ML051520081)
May 31, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Section 4.7.7 TLAA Core Plate Relaxation of Bolts - Response to NRC Request for Additional Information (Accession No. ML051520139)
May 31, 2005	Letter from Mr. M D. Skaggs, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application (LRA) - Response to NRC Request for Additional Information (RAI) concerning follow up to RAIs 2.4-3, 3.5-1, 3.5-4, B.2.1.33-1, and B.2.1.36 (Accession No. ML051520084)
May 31, 2005	Letter from M.L. Marshall, Jr., NRC, to K W. Singer, Tennessee Valleu Authority (TVA) - Browns Ferry Nuclear Plant Unit 1 - Safety Evaluation for Relief Request 1-ISI-19 Associated With Reactor Pressure Vessel Circumferential Shell Welds (Accession No. ML051110626)
June 3, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application –Response to NRC Request for Additional Information on Potential Open Item 3.3.2.35-1 (Accession No. ML051540336)
June 9, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Response to NRC Request for Additional Information (RAI) 4.7.3-1-Radiation Dose for Valve Seals (Accession No. ML051610400)

June 9, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Response to NRC Request for Additional Information (RAI) Concerning follow up to RAI 2.3.3.18-1 and follow up to RAI 2.3.3.22-1(Accession No. ML051610592)
June 15, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Response to NRC Request for Additional Information (RAI) for the Time-limited Aging Analysis identified in 4.7.2 and 4.7.5 of LRA (Accession No. ML051660547)
June 15, 2005	Letter from Mr. T.E.Abney, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Response to NRC Request for Additional Information (RAI) on Clarification for Item 2 of RAI 2.3-2 and RAI 2.3-3 (Accession No. ML051670564)
June 22, 2005	Letter from Ram Subbaratnam, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Request for Additional Information on Section 4.7.7 (Accession No. ML051730507)
June 29, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Response to NRC Request for Additional Information (RAI) concerning Follow up to Section 4.7. 7 Time Limited Aging Analysis RAIs (Accession No. ML0519402910)
August 2, 2005	Letter from Yoira Diaz Sanabria, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Summary of teleconference held on July 7, 2005, with Tennessee Valley Authority (TVA) License Renewal Staff, Concerning Information on Browns Ferry Nuclear Plant, Units 1, 2, and 3 License Renewal Application (Accession No. ML052140646)
August 4, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant - Units 1, 2, and 3 License Renewal Application - Description of Unit 1 Periodic Inspection Program (Accession No. ML052170406)
August 9, 2005	Letter from P.T. Kuo, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Safety Evaluation Report (SER) with Open Items Related to the License Renewal of Browns Ferry Nuclear Plant, Units 1, 2, and 3 (Accession No. ML052210459)
August 9, 2005	Letter from Mr. Brian O'Grady, Browns Ferry Nuclear Plant to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 - Consolidated List of Commitments for License Renewal (Accession No. ML052220070)

September 6, 2005	Letter from Mr. Brian O'Grady, Browns Ferry Nuclear Plant to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application - Response to NRC Request for Additional Information Concerning Follow-Up to RAIs 4.7.7-1 and 4.7.7-2 (Accession No. ML052570462)
September 14, 2005	Letter from Mr. Brian O'Grady, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application - Results of Review of Safety Evaluation Report (SER) with Open Items Related to License Renewal of Browns Ferry Nuclear Plant (Accession No. ML052630075)
October 31, 2005	Letter from Yoira Diaz Sanabria, NRC, to K.W. Singer, Tennessee Valley Authority (TVA) - Summary of teleconference held on October 14 and 18, 2005, with Tennessee Valley Authority (TVA) License Renewal Staff, Concerning Information on Browns Ferry Nuclear Plant, Units 1, 2, and 3 License Renewal Application (Accession No. ML053050358)
November 16, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant - Units 1, 2, and 3 License Renewal Application (LRA) - Supplemental Responses to NRC Requests (Accession No. ML053320331)
November 21, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Nuclear Plant (BFN) - Units 1, 2, and 3 License Renewal Application – Response to NRC Request for Clarification for BFN's use of Linde 80 Weld Material on Unit 1. (Accession No. ML053260542)
December 12, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Units 1, 2, and 3 License Renewal Application (LRA) - Response to NRC Request for Clarification of Commitment Tables Contained in the Safety Evaluation Report (Accession No. ML053460417)
December 20, 2005	Letter from Mr. W.D. Crouch, Tennessee Valley Authority (TVA) to the NRC - Browns Ferry Units 1, 2, and 3 License Renewal Application (LRA) - Response to NRC Request for Clarification of Commitment Tables Contained in the Safety Evaluation Report (Accession No. 053560328)

APPENDIX C
PRINCIPAL CONTRIBUTORS

NAME	RESPONSIBILITY
R. Subbaratnam	Project Manager
Y. Diaz Sanabria	Project Manager
K. Naidu	Quality Assurance
G. Galleti	Quality Assurance
B. Rogers	Quality Assurance
S. Jones	Management Supervision
J. Guo	Plant Systems
F. Akstulewicz	Management Supervision
M. Razzaque	Reactor Systems
R. Dennig	Management Supervision
R. Goel	Plant Systems
J. Raval	Plant Systems
S. Weerakkody	Management Supervision
N. Iqbal	Plant Systems
K. Manoly	Management Supervision
D. Jeng	Civil Engineering
H. Ashar	Civil Engineering
A. Lee	Mechanical Engineering
Y. Li	Mechanical Engineering
S. Bailey	Mechanical Engineering
R. McNally	Mechanical Engineering
M. Hartzman	Mechanical Engineering
R. Jenkins	Management Supervision
A. Pal	Electrical Engineering
G. Cranston	Technical Support
T. Chan	Management Supervision
R. Davis	Materials Engineering
S. Coffin	Management Supervision
M. Mitchell	Management Supervision
B. Elliot	Materials Engineering
G. Cheruvenki	Materials Engineering
L. Lambros	Materials Engineering
L. Lund	Management Supervision
K. Parczewski	Chemical Engineering
A. Hodgdon	Office of General Council

CONTRACTORS

CONTRACTOR	TECHNICAL AREA
Brookhaven National Laboratory	GALL Audit
Information Systems Laboratories	Plant Systems
Legin Group, Inc.	SER Support

APPENDIX D

REFERENCES

This appendix contains a listing of references used in the preparation of the Safety Evaluation Report prepared during the review of the license renewal application for Browns Ferry Nuclear Plant, Units 1, 2, and 3, Docket Numbers 50-259, 50-260, and 50-296, respectively.

(1) NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," April 2001

(2) NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule, Revision 3," August 2001

(3) NUREG-1801, "Generic Aging Lessons Learned Report (GALL)," April 2001

(4) Browns Ferry Nuclear Plant, Units 1, 2, and 3, updated final safety analysis report (UFSAR), Amendment 20.

(5) BWR Vessel and Internals Project Report BWRVIP-25: "BWR Core Plate Inspection and Flaw Evaluation Guidelines," TR-107284, December 1996.

(6) BWR Vessel and Internals Project Report BWRVIP-99: "Crack Growth Rates in Irradiated Stainless Steels in BWR Internal Components," TR-1003018, December 2001.

NRC FORM 335 (9-2004) NRCMD 3.7 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-1843
2. TITLE AND SUBTITLE Safety Evaluation Report Related to the License Renewal of the Browns Ferry Nuclear Units 1, 2, and 3	3. DATE REPORT PUBLISHED MONTH: April YEAR: 2006 4. FIN OR GRANT NUMBER
5. AUTHOR(S) Yoira Diaz-Sanabria Ram Subbaratnam	6. TYPE OF REPORT 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 License Renewal
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 above

10. SUPPLEMENTARY NOTES

11. ABSTRACT *(200 words or less)*

This safety evaluation report (SER) documents the technical review of the Browns Ferry Nuclear Plant (BFN), Units1, 2, and 3, license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff). By letter dated December31, 2003, Tennessee Valley Authority (TVA or the applicant) submitted the LRA for BFN in accordance with Title10, Part54, of the Code of Federal Regulations (10CFRPart54). TVA is requesting renewal of the operating licenses for BFN Units1, 2, and 3, (Facility Operating License Numbers DPR-33, DPR-52, and DPR-68, respectively) for a period of 20 years beyond the current expiration dates of midnight December 20, 2013, for Unit1; midnight June28, 2014, for Unit2; and midnight July2, 2016, for Unit3.

The BFN units are located on the north shore of Wheeler Reservoir in Limestone County, Alabama, at Tennessee River Mile 294. The site is approximately 30 miles west of Huntsville, Alabama; it is also 10 miles northwest of Decatur, Alabama and 10 miles southwest of Athens, Alabama. This SER presents the status of the staff's review of information submitted to the NRC in the application and supplements. The staff's conclusion of its review of the BFN LRAs can be found in Section 6 of this SER.

The NRC license renewal project managers for the BFN license renewal review are Ram Subbaratnam and Yoira Diaz-Sanabria. Mr.Subbaratnam can be contacted by telephone at 301-415-1478 or by electronic mail at rxs2@nrc.gov and Ms.Diaz-Sanabria at 301-415-1594 or by electronic mail at yks@nrc.gov. Written correspondence should be addressed to the U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*	13. AVAILABILITY STATEMENT: unlimited
license renewal, nuclear power	14. SECURITY CLASSIFICATION *(This Page)* unclassified *(This Report)* unclassified
	15. NUMBER OF PAGES
	16. PRICE