SECTION 3

AGING MANAGEMENT REVIEW RESULTS

This section of the SER contains the staff's evaluation of the applicant's aging management programs (AMPs) and aging management reviews (AMRs). In LRA Appendix B, the applicant described the 27 AMPs that it relies on to manage or monitor the aging of long-lived, passive components and structures.

In LRA Section 3, the applicant provided the results of the AMRs for those structures and components that were identified in LRA Section 2 as being within the scope of license renewal and subject to an AMR.

3.0 Applicant's Use of the Generic Aging Lessons Learned Report

In preparing its license renewal application (LRA), Nuclear Management Company (NMC or the applicant) credited NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," dated July 2001. The GALL Report contains the staff's generic evaluation of existing plant programs and documents the technical basis for determining where existing programs are adequate without modification and where existing programs should be augmented for the period of extended operation. The evaluation results documented in the GALL Report indicate that many of the existing programs are adequate to manage the aging effects for particular structures or components for license renewal without change. The GALL Report also contains recommendations on specific areas for which existing programs should be augmented for license renewal. An applicant may reference the GALL Report in an LRA to demonstrate the programs at its facility correspond to those reviewed and approved in the report.

The purpose of the GALL Report is to provide the staff with a summary of staff-approved AMPs to manage or monitor the aging of structures and components that are subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources used to review an applicant's LRA will be greatly reduced, thereby improving the efficiency and effectiveness of the license renewal review process. The GALL Report also serves as a reference for applicants and staff reviewers to quickly identify those AMPs and activities that the staff determined will adequately manage or monitor aging during the period of extended operation.

The GALL Report identifies (1) systems, structures, and components (SSCs), (2) structure and component (SC) materials, (3) the environments to which the SCs are exposed, (4) the aging effects associated with the materials and environments, (5) the AMPs that are credited with managing or monitoring the aging effects, and (6) recommendations for further applicant evaluations of aging management for certain component types.

To determine whether using the GALL Report would improve the efficiency of the license renewal review, the staff conducted a demonstration project to exercise the GALL process and to determine the format and content of a safety evaluation (SE) based on this process. The results of the demonstration project confirmed that the GALL process will improve the efficiency and effectiveness of the LRA review while maintaining the staff's focus on public health and safety. NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plant," dated July 2001 (SRP-LR), was prepared based on both the GALL model and lessons learned from the demonstration project.

The staff performed its LRA review in accordance with the requirements of Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," the guidance provided in NUREG-1800, and the guidance provided in NUREG-1801.

In addition to its LRA review, the staff conducted an onsite audit and review of selected AMRs and associated AMPs as described in the "Audit and Review Report for Plant Aging Management Reviews and Programs, Point Beach Nuclear Plant, Units 1 and 2," dated April 11, 2005 (ML051020288). The onsite audits and reviews are designed to maximize the efficiencies of the staff's LRA review. The need for formal correspondence between the staff and the applicant was reduced and the result was an improvement in the review's efficiency. In addition, the applicant could respond to questions and the staff could readily evaluate the applicant's responses.

3.0.1 Format of the LRA

NMC submitted an application that followed the standard LRA format, as agreed to between the staff and the Nuclear Energy Institute (see letter dated April 7, 2003, ML030990052). This revised LRA format incorporates lessons learned from the staff's reviews of the previous five LRAs. These previous applications used a format developed from information gained during a demonstration project, between the staff and the Nuclear Energy Institute (NEI), conducted to evaluate the use of the GALL Report in the staff's review process.

The organization of LRA Section 3 parallels SRP-LR Chapter 3. The AMR results information in LRA Section 3 is presented in the following two table types.

(1) Table 1: Table 3.x.1 - where "3" indicates the LRA Section number, "x" indicates the subsection number from the GALL Report, and "1" indicates that this is the first table type in LRA Section 3.

(2) Table 2: Table 3.x.2-y - where "3" indicates the LRA Section number, "x" indicates the subsection number of the GALL Report, "2" indicates that this is the second table type in LRA Section 3, and "y" indicates the system table number.

The content of the previous applications and the PBNP application is essentially the same. The intent of the revised format used for the PBNP application was to modify the tables in Chapter 3 to provide additional information to assist the staff in its review. In Table 1 the applicant summarized the portions of the application it considered to be consistent with the GALL Report. In Table 2, the applicant identified the linkage between the scoping and screening results in Chapter 2 and the AMRs in Chapter 3.

3.0.1.1 Overview of Table 1

Table 3.x.1 (Table 1) provides a summary comparison of how the facility aligns with the corresponding tables of the GALL Report, Volume 1. The table is essentially the same as Tables 1 through 6 provided in the GALL Report, Volume 1, except that the "Type" column has been replaced by an "Item Number" column and the "Item Number in GALL" column has been replaced by a "Discussion" column. The "Item Number" column provides the reviewer with a means to cross-reference from Table 2 to Table 1. The "Discussion" column is used by the applicant to provide clarifying/amplifying information. The following are examples of information that might be contained within this column:

- further evaluation recommended - information or reference to where that information is located;
- the name of a plant-specific program being used;
- exceptions to the GALL Report (NUREG-1801) assumptions;
- discussion of how the line item is consistent with the corresponding line item in NUREG-1801, Volume 1, when that may not be intuitively obvious; and
- discussion of how the line item is different from the corresponding line item in the NUREG-1801, Volume 1 (*e.g.*, when there is exception taken to an AMP that is listed in NUREG-1801, Volume 1).

The format of Table 1 provides the reviewer with a means of aligning a specific Table 1 row with the corresponding NUREG-1801, Volume 1 table row, thereby allowing for the ease of checking consistency.

3.0.1.2 Overview of Table 2

Table 3.x.2-y (Table 2) provides the detailed results of the AMRs for those components identified in LRA Section 2 as being subject to an AMR. The LRA contains a Table 2 for each of the components or systems within a system grouping (*e.g.*, reactor coolant systems, engineered safety features, auxiliary systems). For example, the engineered safety features group contains tables specific to the containment spray system, containment isolation system, and emergency core cooling system. Table 2 consists of the following nine columns:

(1) Component Type - The first column identifies the component types from LRA Section 2 that are subject to AMR. They are listed in alphabetical order.

(2) Intended Function - The second column contains the license renewal intended functions (including abbreviations, where applicable) for the listed component types. Definitions and abbreviations of intended functions are contained within the "Intended Functions" table of LRA Section 2.

(3) Material - The third column lists the particular materials of construction for the component type.

(4) Environment - The fourth column lists the environment to which the component types are exposed. Internal and external service environments are indicated and a list of

these environments is provided in the "Internal Service Environments and External Service Environments" tables of LRA Section 3.

(5) Aging Effect Requiring Management - As part of the AMR process, the applicant determines any aging effects requiring management for the material and environment combination in order to maintain the intended function of the component type. These aging effects requiring management are listed in column five.

(6) Aging Management Programs - The sixth column lists the AMPs the applicant used to manage the identified aging effects.

(7) GALL Volume 2 Item - Each combination of component type, material, environment, aging effect requiring management, and AMP that is listed in Table 2, is compared to NUREG-1801, Volume 2, with consideration given to the standard notes, to identify inconsistencies. When they are identified, they are documented by noting the appropriate NUREG-1801, Volume 2 item number in column seven of Table 2. If there is no corresponding item number in NUREG-1801, Volume 2, this row in column seven is left blank. That way, a reviewer can readily identify where there is correspondence between the plant-specific tables and the NUREG-1801, Volume 2 tables.

(8) Table 1 Item - Each combination of component, material, environment, aging effect requiring management, and AMP that has been identified in NUREG-1801, Volume 2 item number must also have a Table 3.x.1 line item reference number. The corresponding line item from Figure 3.0-1 is listed in column eight of Table 2. If there is no corresponding item in NUREG-1801, Volume 1, this row in column eight is left blank. That way, the information from the two tables can be correlated.

(9) Notes - In order to realize the full benefit of NUREG-1801, each applicant should identify how the information in Table 2 aligns with the information in NUREG-1801, Volume 2. This is accomplished through a series of notes. All note references with letters are standard notes that will be the same from application to application throughout the industry. Any plant-specific notes, which are in addition to the standard notes, will be identified by a number.

3.0.2 Staff's Review Process

The staff conducted the following three types of evaluations of the AMRs and associated AMPs.

(1) For items that the applicant stated were consistent with the GALL Report, the staff conducted either an audit or a technical review to determine consistency with the GALL Report.

(2) For items the applicant stated were consistent with the GALL Report with exceptions and/or enhancements, the staff conducted either an audit or a technical review of the item to determine consistency with the GALL Report. In addition, the staff conducted either an audit or a technical review of the applicant's technical justification for the exceptions and the adequacy of the enhancements.

(3) For other items, the staff conducted a technical review pursuant to 10 CFR 54.21(a)(3).

The staff performed audits and technical reviews of the applicant's AMPs and AMRs. These audit and technical reviews determined whether the effects of aging on structures and components can be adequately managed so that their intended functions can be maintained consistently with the plant's current licensing basis (CLB) for the period of extended operation as required by 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

The staff performed onsite audits during the weeks of April 26 and June 7, 2004, to verify selected AMPs and AMR results that the applicant claimed were consistent with the GALL Report were actually consistent as claimed. The staff conducted a public exit meeting on July 15, 2004. Details of the staff's onsite audit are documented in the "Audit and Review Report for Plant Aging Management Reviews - Point Beach Nuclear Plant, Units 1 and 2," dated April 11, 2005 (ML051020288).

3.0.2.1 Review of AMPs

For those AMPs for which the applicant claimed consistency with the GALL AMPs, the staff conducted either an audit or a technical review to verify that the applicant's AMPs were consistent with those in the GALL Report. For each AMP that had one or more deviations, the staff evaluated each deviation to determine: (1) whether the deviation was acceptable, and (2) whether the AMP, as modified, would adequately manage the aging effect(s) for which it was credited.

For AMPs that were not evaluated in the GALL Report, the staff performed a full review to determine the adequacy of the AMPs. The staff evaluated the AMPs against the following 10 program elements defined in SRP-LR Appendix A.

(1) Scope of the Program - The scope of the program should include the specific SCs subject to an AMR for license renewal.

(2) Preventive Actions - Preventive actions should prevent or mitigate aging degradation.

(3) Parameters Monitored or Inspected - The parameters monitored or inspected should be linked to the degradation of the particular structure or component intended functions(s).

(4) Detection of Aging Effects - Detection of aging effects should occur before there is a loss of structure or component intended functions(s). This includes aspects such as method or technique (*i.e.*, visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new/one-time inspections to ensure timely detection of aging effects.

(5) Monitoring and Trending - Monitoring and trending should provide predictability of the extent of degradation, and timely corrective or mitigative actions.

(6) Acceptance Criteria - Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the structure or component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

(7) Corrective Actions - Corrective actions, including root cause determination and prevention of recurrence, should be timely.

(8) Confirmation Process - The confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

(9) Administrative Controls - Administrative controls should provide a formal review and approval process.

(10) Operating Experience - Operating experience of the AMP, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the SC intended function(s) will be maintained during the period of extended operation.

Details of the staff's audit evaluation of program elements (1) through (6) are documented in its audit and review report and are summarized in SER Section 3.0.3.

The staff reviewed the applicant's quality assurance program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the quality assurance program included assessment of the following program elements: (7) corrective actions, (8) confirmation process, and (9) administrative controls.

The staff reviewed the information concerning program element (10), operating experience, and documented this evaluation in its audit and review report. This information is summarized in SER Section 3.0.3.

The staff also reviewed the final safety analysis report (FSAR) supplement for each AMP to determine if it provided an adequate description of the program or activity, as required by 10 CFR 54.21(d).

3.0.2.2 Review of AMR Results

LRA Table 2 contains information concerning whether or not the AMRs align with the AMR information identified in the GALL Report. For a given AMR in Table 2, the staff reviewed the intended function, material, environment, aging effect requiring management, and AMP combination for a particular component type within a system. The AMRs that correlate between a combination in Table 2 and a combination in the GALL Report were identified by a referenced item number in column seven, "GALL, Volume 2 Item." The staff also conducted onsite audits to verify the correlation. A blank column seven indicates that the applicant was unable to locate an appropriate corresponding combination in the GALL Report. The staff conducted a technical review of these combinations that were not consistent with the GALL Report. The next column, "Table 1 Item," provided a reference number that indicated the corresponding row in Table 1.

3.0.2.3 FSAR Supplement

Consistent with the SRP-LR, for the AMRs and associated AMPs that it reviewed, the staff also reviewed the FSAR supplement that summarizes the applicant's programs and activities for managing the effects of aging for the period of extended operation, as required by 10 CFR 54.21(d).

3.0.2.4 Documentation and Documents Reviewed

In performing its review, the staff relied heavily on the LRA, the LRA supplements, the SRP-LR, and the GALL Report.

Also, during the onsite audit, the staff examined the applicant's justification, as documented in the staff's PBNP audit and review report, to verify that the applicant's activities and programs will adequately manage the effects of aging on SCs. The staff also conducted detailed discussions and interviews with the applicant's license renewal project personnel and others with technical expertise relevant to aging management.

3.0.3 Aging Management Programs

Table 3.0.3-1 presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates the GALL Report AMP that the applicant claimed its AMP was consistent with (if applicable) and the SSCs for managing or monitoring aging. The section of the SER in which the staff's evaluation of the program is documented is provided.

Table 3.0.3-1 PBNP's Aging Management Programs

PBNP AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures that Credit the AMP	Staff's SER Section
ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.1)	Consistent with exceptions and enhancements	XI.M1 XI.M3	Reactor coolant system	3.0.3.2.1
ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.2)	Consistent with exceptions and enhancements	XI.S1 XI.S2 XI.S4	Containments, structures, and component supports	3.0.3.2.2
ASME Section XI, Subsection IWF Inservice Inspection Program (B2.1.3)	Consistent with exceptions and enhancements	XI.S3	Containments, structures, and component supports	3.0.3.2.3
Bolting Integrity Program (B2.1.4)	Consistent with exceptions and enhancements	X1.M18	Reactor coolant system; engineered safety features; auxiliary systems; steam and power conversion system	3.0.3.2.4
Boraflex Monitoring Program (B2.1.5)	Consistent with enhancements	X1.M22	Containments, structures, and component supports	3.0.3.2.5

PBNP AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures that Credit the AMP	Staff's SER Section
Boric Acid Corrosion Program (B2.1.6)	Consistent with enhancements	XI.M10	Reactor coolant system; engineered safety features; auxiliary systems; steam and power conversion system; containments, structures, and component supports; electrical and instrumentation and controls	3.0.3.2.6
Buried Services Monitoring Program (B2.1.7)	Consistent with enhancements	XI.M34	Auxiliary systems	3.0.3.2.7
Cable Condition Monitoring Program (B2.1.8)	Consistent with exceptions and enhancements	XI.E1 XI.E2 XI.E3	Electrical and instrumentation and controls	3.0.3.2.8
Closed-Cycle Cooling Water System Surveillance Program (B2.1.9)	Consistent with exceptions and enhancements	XI.M21	Reactor coolant system; engineered safety features; auxiliary systems	3.0.3.2.9
Fire Protection Program (B2.1.10)	Consistent with exceptions and enhancements	XI.M26 XI.M27	Auxiliary systems; containments, structures, and component supports	3.0.3.2.10
Flow-Accelerated Corrosion Program (B2.1.11)	Consistent with exceptions and enhancements	XI.M17	Reactor coolant system; steam and power conversion system	3.0.3.2.11
Fuel Oil Chemistry Control Program (B2.1.12)	Consistent with exceptions and enhancements	XI.M30	Auxiliary systems	3.0.3.2.12
One-Time Inspection Program (B2.1.13)	Consistent with exceptions and enhancements	XI.M32 XI.M33	Reactor coolant system; engineered safety features; auxiliary systems; steam and power conversion system	3.0.3.2.13
Open-Cycle Cooling (Service) Water System Surveillance Program (B2.1.14)	Consistent with exceptions and enhancements	XI.M20	Auxiliary systems; steam and power conversion system	3.0.3.2.14
Periodic Surveillance and Preventive Maintenance Program (B2.1.15)	Plant-specific		Reactor coolant system; engineered safety features; auxiliary systems; steam and power conversion system; containments, structures, and component supports	3.0.3.3.1
Reactor Coolant System Alloy 600 Inspection Program (B2.1.16)	Consistent with exceptions and enhancements	XI.M11	Reactor coolant system	3.0.3.2.15
Reactor Vessel Internals Program (B2.1.17)	Consistent with exceptions and enhancements	XI.M13 XI.M16	Reactor coolant system	3.0.3.2.16

PBNP AMP (LRA Section)	GALL Comparison	GALL AMP(s)	LRA Systems or Structures that Credit the AMP	Staff's SER Section
Reactor Vessel Surveillance Program (B2.1.18)	Consistent with exceptions and enhancements	XI.M31	Reactor coolant system	3.0.3.2.17
Steam Generator Integrity Program (B2.1.19)	Consistent with enhancements	XI.M19	Reactor coolant system	3.0.3.2.18
Structures Monitoring Program (B2.1.20)	Consistent with exceptions and enhancements	XI.M23 XI.S5 XI.S6 XI.S7	Containments, structures, and component supports	3.0.3.2.19
Systems Monitoring Program (B2.1.21)	Plant-specific and in part, is consistent with exceptions and enhancements	XI.M29	Reactor coolant system; engineered safety features; auxiliary systems; steam and power conversion system	3.0.3.3.2
Tank Internal Inspection Program (B2.1.22)	Plant-specific		Auxiliary systems; steam and power conversion system	3.0.3.3.3
Thimble Tube Inspection Program (B2.1.23)	Plant-specific		Reactor coolant system	3.0.3.3.4
Water Chemistry Control Program (B2.1.24)	Consistent with exceptions and enhancements	XI.M2	Reactor coolant system; engineered safety features; auxiliary systems; steam and power conversion system; containments, structures, and component supports	3.0.3.2.20
Environmental Qualification Program (B3.1)	Consistent with enhancements	X.E1	Electrical and Instrumentation and Controls	3.0.3.2.21
Fatigue Monitoring Program (B3.2)	Consistent with enhancements	X.M1	Metal Fatigue (LRA Section 4.3)	3.0.3.2.22
Pre-Stressed Concrete Containment Tendon Surveillance Program (B3.3)	Consistent with enhancements	X.S1	Loss of Preload (LRA Section 4.5)	3.0.3.2.23

3.0.3.1 AMPs That Are Consistent with the GALL Report

In LRA Appendix B, the applicant indicated that most of its AMPs are consistent, but with exceptions and/or enhancements, to the GALL Report. The staff's evaluation of these programs is documented in SER Section 3.0.3.2. The Periodic Surveillance and Preventive Maintenance Program, System Monitoring Program, Tank Internal Inspection Program, and Thimble Tube Inspection Program are considered as PBNP plant-specific. The staff's evaluation of these programs is documented in SER Section 3.0.3.3.

3.0.3.2 AMPs That Are Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant indicated that the following AMPs were, or will be consistent with the GALL Report with exceptions and/or enhancements:

- ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program (B2.1.1)
- ASME Section XI, Subsections IWE and IWL Inservice Inspection Program (B2.1.2)
- ASME Section XI, Subsections IWF Inservice Inspection Program (B2.1.3)
- Bolting Integrity Program (B2.1.4)
- Boraflex Monitoring Program (B2.1.5)
- Boric Acid Corrosion Program (B2.1.6)
- Buried Services Monitoring Program (B2.1.7)
- Cable Condition Monitoring Program (B2.1.8)
- Closed-Cycle Cooling Water System Surveillance Program (B2.1.9)
- Fire Protection Program (B2.1.10)
- Flow-Accelerated Corrosion Program (B2.1.11)
- Fuel Oil Chemistry Control Program (B2.1.12)
- One-Time Inspection Program (B2.1.13)
- Open-Cycle Cooling (Service) Water System Surveillance Program (B2.1.14)
- Reactor Coolant System Alloy 600 Inspection Program (B2.1.16)
- Reactor Vessel Internals Program (B2.1.17)
- Reactor Vessel Surveillance Program (B2.1.18)
- Steam Generator Integrity Program (B2.1.19)
- Structures Monitoring Program (B2.1.20)
- Water Chemistry Control Program (B2.1.24)
- Environmental Qualification Program (B3.1)
- Fatigue Monitoring Program (B3.2)
- Pre-Stressed Concrete Containment Tendon Surveillance Program (B3.3)

For AMPs that the applicant claimed are consistent with the GALL Report with exceptions and/or enhancements, the staff performed an audit to confirm that those attributes or features of the program for which the applicant claimed consistency with the GALL Report were indeed consistent. The staff also reviewed the exceptions and/or enhancements to the GALL Report to determine whether they were acceptable and adequate.

The staff determined that the applicant used the word "enhancement" to describe two types of revisions to plant procedures or program activities. First, the applicant used "enhancement" to describe a programmatic revision to achieve consistency with the GALL Report. The staff reviewed these programmatic revisions pursuant to the process described in the staff's audit and review plan.

The applicant also used the word "enhancement" to describe revisions that were required only by the applicant's internal administrative implementing documents. This type of administrative revision is not necessary to demonstrate consistency with the GALL Report criteria. Therefore, the staff considered this type of revision to be an administrative enhancement that does not require staff review.

The results of the staff's audit and reviews of the applicant's AMPs are documented in the following sections.

3.0.3.2.1 ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program

Summary of Technical Information in the Application. The applicant's ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is described in LRA Section B2.1.1, "ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program." In the LRA, the applicant stated that this is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.M1, "ASME Section XI, Subsections IWB, IWC, & IWD," and GALL AMP XI.M3, "Reactor Head Closure Studs."

The applicant stated that the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is credited for managing the aging effects in Class 1, 2, and 3 piping, components and their integral attachments. Specifically, inspections are performed to identify and correct degradation in Class 1, 2, and 3 piping, components and their integral attachments. The program includes periodic visual, surface and/or volumetric examinations and leakage tests of all Class 1, 2, and 3 pressure-retaining components, and their integral attachments, including welds, pump casings, valve bodies, and pressure-retaining bolting. These components and their integral attachments are identified in ASME Code Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," or commitments requiring augmented inservice inspections, and are within the scope of license renewal. This program is in accordance with 10 CFR 50.55a and NRC-approved code cases and relief requests.

In LRA Section 2.1.1.3.8, the applicant addressed its approach of one-time inspection of small bore piping for Class 1 piping welds. The applicant stated that the risk-informed inservice inspection (RI-ISI) program inspections of piping welds less than 4-inch nominal pipe size (NPS) will include volumetric examinations, with exception of socket welded connections. A surface examination will be substituted for inspection of socket welds until a meaningful volumetric inspection technique is created for the geometry presented by socket welds.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with exceptions, remains adequate to manage the aging effects for which it is credited.

In LRA Section B2.1.1, the applicant stated that its ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is consistent with GALL AMP XI.M1, with exceptions and enhancements.

The ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program takes exceptions to the "scope of the program" program element for GALL AMP XI.M1. The applicant identified exceptions to IWB-1220, IWC-1220, but not IWD-1220. Specifically, the applicant's exceptions included (1) use of the exemption criteria found in IWB-1220 of the ASME Code Section XI, 1989 Edition, as required by 10 CFR 50.55a, and (2) use of the exemptions associated with IWC-1220 of ASME Code Section XI 1998 Edition through 2000 Addenda (98A00) for the auxiliary feedwater system piping, vessels, pumps, valves and their connections in piping between 4-inch and 1 ½-inch NPS. The applicant also stated that these exceptions will result in fewer components being exempted from the ASME Code requirements.

For the first exception, 10 CFR 50.55a(b)(2)(xi) states that for Class 1 piping, applicants are not permitted to apply the criteria that allows exemption from inspection of the components listed in IWB-1220 of ASME Code Section XI, 1989 Addenda through the latest edition. Rather, 10 CFR 50.55a(b)(2)(xi) directs the applicant to perform inspections of the components listed in IWB-1220 of ASME Code Section XI, 1989 Edition without the exceptions. This exception to the GALL Report is consistent with the requirements of 10 CFR 50.55a and was in the scope of the ASME Code evaluation documented in the GALL Report Volume 2, Chapter 1. On the basis of its review and ASME Code evaluation performed as part of the GALL Report, the staff found this exception acceptable.

For the second exception, the ASME Code 98A00 deleted the IWC-1220 exception that was permitted by the ASME Code 1995 Edition through 1996 Addenda (95A96). Section 50.55a of 10 CFR was amended in 2001 to adopt ASME Code 98A00. In the Federal Register statement of consideration (67 FR 60520) for this rulemaking, the staff documented its evaluation of ASME Code 98A00 to determine if the recommendations and conclusions of the GALL Report are also applicable for AMPs that rely on the ASME Code which are incorporated into 10 CFR 50.55a by the final rule. For ASME Code 98A00, the staff found that the GALL Report remains valid and justified the use of ASME Code 98A00 as an alternative to ASME Code 95A96 without the need for the applicant to submit to the NRC its plant-specific justification associated with license renewal. On the justification of its review, the staff found this exception acceptable. Furthermore, the basis for this finding applies to all exceptions to ASME Code Section XI, Subsections, which identify the exception of using the ASME Code 98A00 version rather than the ASME Code 95A96 version, as identified in the GALL Report.

The ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program takes exceptions to the "parameters monitored or inspected" and "detection of aging effects" program elements for GALL AMP XI.M1, in that the applicant will use the ASME Code 98A00, Section XI. Specifically, the applicant's ISI Program (1) is currently based on the ASME Code 98A00 Section XI, (2) will implement risk-informed ISI (RI-ISI) for examination categories B-F, B-J, C-F-1, and C-F-2, (3) will modify the sequence of examinations for welds, (4) will examine only one of the three vessels comprising the regenerative heat exchanger for Category B-D, (5) will use technical specification surveillance testing as an alternative to the system leakage test of Class 3 pressure-retaining components of the emergency diesel generator support systems for Category D-B, (6) will use alternative requirements of ASME Code Cases N-533-1, N-566-1, and apply N-616, and (7) will only perform visual examination for Class 1 pump casing welds, as specified in ASME Code 98A00.

The ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program also takes exception to the "parameters monitored or inspected" and "detection of aging effects" program elements for GALL AMP XI.M3, in that the applicant will use the ASME Code Section XI, 98A00. In addition, it takes two exceptions to the "monitoring and trending" program element for GALL AMP XI.M1. Specifically, the applicant stated that (1) IWB-2420(b) of ASME

Code 98A00 allows use of the acoustic emission to monitor growth of existing flaws in lieu of successive examinations during the next three inspection periods and (2) the exception modifies the sequence of the examination established in the previous inspection interval in a manner that reduces scaffolding, insulation and radiation inspection.

The staff's review of LRA Section B2.1.1 identified an area in which additional information was necessary to complete the review of the applicant's program elements. The applicant responded to the staff's request for additional information (RAI) as discussed below.

RAI B2.1. Several currently approved relief requests, shown in RAI Table 1, were reviewed by the project team during the audit and review of the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program. The relief requests were presented as the bases for taking exceptions to the following GALL Report AMPs:

- GALL Section XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"
- GALL Section XI.M3, "Reactor Head Closure Studs"
- GALL Section XI.S1, "ASME Section XI, Subsection IWE"
- GALL Section XI.S2, "ASME Section XI, Subsections IWL"

Relief requests are approved by the NRC as described in 10 CFR 50.55a, Codes and Standards. Relief requests only apply to CLB issues and are time-limited. Consequently, citing approved requests cannot be used as a basis for taking exception to the GALL since they may not be renewed.

Each exception to the GALL Report must be evaluated for NRC approval based on the technical bases that are associated with aging management regardless of whether there is an approved, related relief request. Also, it should be noted that approval of an exception to GALL with respect to a plant's AMP does not mean that a relief request that covers the same issue will be approved during the period of extended operation. The 10 CFR 50.55a process must still be used for relief request approval. Citing a relief request does not provide an acceptable basis to take an exception to GALL.

In RAI B2.1, dated March 30, 2005, the staff requested the applicant to provide the technical bases, as they relate to aging management, without referencing relief requests, for the exceptions taken to the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program and the ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program. This was identified as open item (OI) B2.1.

In its response to OI B2.1, by letter dated July 5, 2005, the applicant withdrew the following alternatives, initially credited as exceptions in the LRA:

- Altering the Date of the Start of the Fourth Inspection Interval
- Alternate Requirements to Repair and Replacement Documentation Requirements and Inservice Inspection Summary Report Preparation and Submission as Required by IWA-4000 and IWA-6000 (Code Case N-532-1)

- Alternate Requirements for VT-2 Visual Examination of Class 1, 2, and 3 Insulated Pressure-Retaining Bolted Connections (Code Case N-533-1)
- Corrective Action for Leakage Identified at Bolted Connections (Code Case N-566-1)
- Successive Inspections (Code Case N-624)
- Alternative to Welding and Brazing Performance Qualification Requirements (Code Case N-600)
- Relief from Regenerative Heat Exchanger Examinations
- Emergency Diesel System VT-2 Examination
- Request for Alternative to ASME Section XI, Appendix VIII, Supplement 10

The applicant clarified in its letter that these alternatives are not exceptions to the GALL Report, as they are either administrative and did not affect aging management, or the aging effect was managed by another AMP cited in the LRA. The staff found each of the bases provided in the applicant's RAI response acceptable and agreed that these alternatives are not exceptions to the GALL Report. The staff found the withdrawal of these alternatives acceptable.

In addition, in its July 5, 2005, letter, the applicant withdrew its exception concerning the use of ASME Code, Section XI, 1998 Edition with Addenda through 2000. The staff found this withdrawal acceptable based on the understanding that Westinghouse performed a fracture toughness analysis for Class 1 pump casing welds, as discussed in the original LRA Section 4.4.3. This Westinghouse analysis addressed Code Case N-481, which was endorsed by the staff in RG 1.147 and found to be an acceptable alternative to volumetric examinations. The staff found the combination of VT-1 examination per A2000 and flaw tolerance analysis to be technically acceptable to manage the aging effects of Class 1 pump casing welds.

With respect to the Alternative Requirements for VT-2 Visual Examination of Class 1, 2, and 3 Insulated Pressure-Retaining Bolted Connections, Section XI, Division 1 (Code Case N-616), the applicant withdrew its exception and provided the following commitment:

> As a part of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, the requirements of Code Case N-616 will be supplemented by a VT-2 visual examination performed each outage for Class 1 systems and each inspection period for Class 2 and 3 systems with the insulation removed from the bolted connections. The connections are not pressurized during these examinations.

With the inclusion of the above commitment, the staff found the aging management program consistent with the GALL Report AMP XI.M1, "ASME Section XI Inservice Inspection, Subsection IWB, IWC and IWD." The staff found the withdrawal of this exception acceptable.

In addition, the applicant provided, in part, the following technical basis in support of its GALL Report exception for the Risk-Informed Examination of Class 1 and Class 2 Piping Butt Welds (Code Case N-578 and EPRI TR-112657):

> This alternative implements a Risk-Informed Inservice Inspection (RI-ISI) Program for ASME Class 1 and 2 piping welds (Categories B-F, B-J, C-F-1, and C-F-2 only), for both PBNP Units 1 and 2. The RI-ISI program provides an acceptable alternative to the piping ISI requirements with regards to (1) the number of locations, (2) the locations of

inspections, and (3) the method of inspection. The RI-ISI program maintains the fundamental requirements of ASME Section XI, such as the examination technique, examination frequency, and acceptance criteria. Although the RI-ISI program reduces the number of required examination locations in some cases, it maintains an acceptable level of quality and safety by focusing inspections on the most safety significant welds with nondestructive examination (NDE) techniques that are more focused towards finding the type of expected degradation as well as the types of flaws and degradation found during traditional inspections.

A systematic approach was used to identify component susceptibility to common degradation mechanisms and to categorize these degradation mechanisms into the appropriate degradation categories with respect to their potential to result in a postulated leak or rupture in the pressure boundary. An evaluation to determine the susceptibility of components to a particular degradation mechanism that may be a precursor to a leak or rupture in the pressure boundary, and an independent assessment of the consequences of a failure at that location were performed. Industry and plant-specific piping failure information (*i.e.*, operating experience) was used to identify piping degradation mechanisms and failure modes, and consequence evaluations performed using PRAs to establish safety ranking of piping segments for selecting new inspection locations. The degradation mechanisms identified in the RI-ISI program include thermal fatigue, thermal transients, intergranular stress-corrosion cracking (IGSCC), and primary water stress-corrosion cracking (PWSCC). The consequences of pressure boundary failures were evaluated and ranked on their impact on core damage and early release. Therefore, redistributing the welds to be inspected with consideration of the safety significance of the segments provides assurance that segments whose failure have a significant impact on plant risk receive an acceptable and improved level of inspection.

... This alternative is also credited for the inspection of small bore piping prior to the period of extended operation instead of the One-Time Inspection Program, as recommended in NUREG-1801 Section XI.M32. The RI-ISI program will require examination of a sample of susceptible risk significant small bore (< 4 inch) ASME Class 1 and 2 piping. The RI-ISI program will require volumetric examination of non-socket welds and surface examination of socket welds in the sample. Approximately twenty small bore piping locations per unit will be examined under the RI-ISI program. Therefore, the RI-ISI program provides an acceptable alternative with regards to (1) the number of locations, (2) the locations of inspections, and (3) the method of inspection for small bore ASME Class 1 and 2 piping.

The staff found this exception to the management of aging effects acceptable because:

- It is applicable only to ASME Class 1 and 2 piping welds (Categories B-F, B-J, C-F-1, and C-F-2),
- The RI-ISI program maintains the ASME Section XI, fundamental requirements for the examination technique, examination frequency, and acceptance criteria,
- It inspects a sample of locations that are the most safety significant with consideration of industry and plant-specific piping operating experience, and

- It manages the aging effects of thermal fatigue, thermal transients, IGSCC, and PWSCC, which are the aging effects of interest in the LRA AMRs.

Furthermore, the staff found the use of the RI-ISI methods an appropriate method to identify the location and inspection method of small bore pipes. The use of this AMP as an exception to using the One-Time Inspection AMP defined in the GALL Report results in a larger number of smallbore pipes being volumetrically inspected and, therefore, provides a greater population of inspection results to determine if an active aging effect is occurring in the small bore piping.

Based on the discussion above, the staff concluded that the applicant's response to RAI B2.1 is acceptable. The staff's concerns with respect to the ASME Section XI, Subsections IWB, IWC, and IWD exceptions are resolved; further discussions on remaining exceptions related to Subsections IWE, and IWL, and Subsection IWF are documented in SER Sections 3.0.3.2.2 and 3.0.3.2.3, respectively. The staff concluded that this part of OI B2.1 is closed.

In LRA Section B2.1.1 the applicant stated that its ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program is consistent with GALL AMP XI.M1 and GALL AMP XI.M3, with enhancements. The applicant stated that, for the "detection of aging effects" program element, enhancements include revisions to existing activities credited for license renewal to ensure that inspections for the applicable aging effects are performed and any noted indications are appropriately evaluated. Enhancements to plant process control procedures will be made to ensure that use of flaw tolerance evaluation or the enhanced volumetric examination of welded connections and cast austenitic stainless steel (CASS) in Class 1 components. A new leak-before-break (LBB) analysis, based on thermally aged material properties, was performed throughout the period of extended operation.

<u>Operating Experience</u>. The staff reviewed the applicant's operating experience for the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The staff found that the plant-specific operating experience indicates that visual inspections have proven to be effective in managing the aging effects of ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program components.

The applicant stated that review of industry operating experience related to the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program revealed numerous instances of primary pressure boundary degradation and that the instances of degradation generally fall into the following categories: (1) boric acid corrosion caused by leakage at mechanical connections, (2) cracking caused by thermal fatigue, (3) degradation of bolting caused by stress corrosion cracking (SCC) of high-strength bolts or boric acid corrosion, and (4) leaks or cracks caused by PWSCC of Alloy 600 components.

The applicant also stated that most of the indications found by examinations required by its ISI programs have been evidence of borated water leakage at mechanical joints such as flange connections and valve bonnets. The applicant stated that a search of condition reports and maintenance work orders on reactor vessel head closure studs revealed that no degradation of the studs or nuts had been detected.

The applicant stated that a review of plant-specific operating experience revealed two instances where ISI examinations discovered flaws through means other than the system leakage test.

Unacceptable flaw indications were discovered in each reactor vessel outlet nozzle-to-shell weld during the ultrasonic examination of reactor vessel welds at Unit 1 in 1984. The applicant performed a fracture mechanics evaluation that demonstrated that the flaws posed no threat to continued safe operation of the reactor vessel. The applicant stated that subsequent inspections resized the flaws using more accurate techniques and that the flaws were determined to be within code allowances.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.1, the applicant provided the FSAR supplement for the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.2 ASME Section XI, Subsections IWE and IWL Inservice Inspection Program

Summary of Technical Information in the Application. The applicant's ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program is described in LRA Section B2.1.2 "ASME Section XI, Subsections IWE and IWL Inservice Inspection Program." The applicant stated that this is an existing program that is consistent with GALL AMP XI.S4, "10 CFR Part 50 Appendix J." This program is also consistent, with exceptions and enhancements, with GALL AMP XI.S1, "ASME Section XI, Subsection IWE," and GALL AMP XI.S2, "ASME Section XI, Subsection IWL."

The applicant stated that the ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program, is credited for managing the aging effects of (1) steel liners of concrete containments and their integral attachments; containment hatches and airlocks; seals, gaskets, and moisture barriers; and pressure-retaining bolting; and (2) reinforced concrete containments and unbonded post-tensioning systems. The primary inspection methods employed are visual examinations with limited supplemental volumetric and surface examinations, as necessary. Tendon anchorages and wires are examined visually. Tendon wires are tested to verify that minimum mechanical property requirements are met. Tendon corrosion protection medium is analyzed for alkalinity, water content, and soluble ion concentrations. Prestressing forces are measured in sample tendons. Measured tendon lift-off forces are compared to predicted tendon forces calculated in accordance with RG 1.35.1, "Determining Prestressing Forces for Inspection of Prestressed Concrete Containments." The applicant stated that this program is in accordance with 10 CFR 50.55a and NRC-approved code cases and relief requests. In addition, the applicant stated that this program is credited by the Bolting Integrity Program, for the inspection of pressure-retaining bolting associated with the containment pressure boundary.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In LRA Section B2.1.2, the applicant stated that its ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program is consistent with GALL AMP XI.S4 and is consistent with GALL AMPs XI.S1 and XI.S2, with exceptions.

The applicant takes exception to the "parameters monitored or inspected" and "acceptance criteria" program elements in that the applicant's program is based on different versions of the American Concrete Institute (ACI) Code for concrete degradation. Specifically, the GALL AMP, ASME Code Section XI, Subsections IWE, and IWL Inservice Inspection Program cites ACI 201.1R-68, "Guide for Making a Condition Survey of Concrete in Service," instead of ACI 201.1R-77 as a reference for concrete degradation. GALL AMP XI.S2 cites ACI 201.1R-77 as a source of information. The applicant also stated that the earlier version is consistent with the 1992 Addenda of IWL-2510 and Table IWA-1600-1.

The staff found that the earlier ACI version is identical to the later ACI version except for date of issue. Also the earlier version is part of the applicant's CLB. On the basis that the earlier ACI version is identical to the later ACI version except for date of issue, the staff found this exception acceptable.

The applicant also takes exception to the "detection of aging effects" program elements for GALL AMPs XI.S1 and XI.S2 in that (1) qualification of NDE personnel to a written practice in accordance with SNT-TC1A is performed instead of CP-189, which is required by IWA-2300, and (2) relaxation of illumination and direct examination distance requirements of IWA-2210 and allowing general visual inspection of inaccessible concrete surfaces instead of the VT-3 examination required by IWL-2510(a), for GALL AMP XI.S2 only. The applicant justified these exceptions based on an NRC-approved relief request.

The staff found that the applicant relied on ASME Code relief requests as its justification for the exceptions. The staff found that use of an NRC-approved relief request is not an appropriate basis for justifying an exception to the GALL Report. As discussed in the GALL Report, Volume 2, Chapter 1, the staff evaluated the ASME Code 95A96 version pursuant to the ten program elements to assure that the aging effects will be adequately managed. The staff, when it approved a relief request per the requirements of 10 CFR 50.55a, did not evaluate the exception to assure that the aging effect will be adequately managed during the period of extended operation.

The ASME Code Section XI, Subsections IWE, and IWL Inservice Inspection Program relied on the approved relief request as part of the justification for the exceptions. In RAI B2.1, as discussed in SER Section 3.0.3.2.1, the staff requested the applicant to clarify the use of the relief request and to provide technical justification for these exceptions. This was identified as open item (OI) B2.1.

In its response to OI B2.1, by letter dated July 5, 2005, the applicant withdrew the following alternatives, initially credited as exceptions in the LRA:

- Elimination of VT-3 Examinations of Seals and Gaskets
- No Successive Examination of Repairs
- Elimination of Required Bolt Torque or Tension Tests
- Elimination of the Need for Venting of Leak Chase Channels During Integrated Leak Rate Tests
- Allowing the Qualification and Certification of NDE Personnel to a Written Practice in Accordance with SNT-TC1A Instead of CP-189
- Relaxing the Illumination and Direct Examination Distance Requirements of IWA-2210
- Allowing a General Visual Inspection of Inaccessible Concrete Surfaces Instead of the VT-3 Examination Required by IWL-2510(a)

The applicant clarified in its letter that each of these alternatives are not exceptions to the GALL Report as they are either administrative, and did not affect aging management, or the aging effect was managed by another AMP cited in the LRA. The staff found each of the bases identified in the applicant's RAI response acceptable and agreed that these alternatives are not exceptions to the GALL Report. The staff found the withdrawal of these alternatives acceptable.

Based on the discussion above, the staff concluded that the applicant's response to RAI B2.1 is acceptable. The staff's concerns with respect to the ASME Section XI, Subsections IWE and IWL exceptions are resolved. Further discussions on remaining exceptions related to Subsections IWA, IWB and IWC and Subsection IWF are documented in SER Sections 3.0.3.2.1 and 3.0.3.2.3, respectively. The staff concluded that this part of OI B2.1 is closed.

In LRA Section B2.1.2, the applicant stated that its ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program is consistent with GALL AMPs XI.S4, XI.S1, and XI.S2, with enhancements. The applicant stated that, for the "detection of aging effects" program element, enhancements include modification to procedures to clarify that (1) test results are documented in accordance with 10 CFR Part 50, Appendix J and (2) yield strength for tendon wire samples will be determined in accordance with IWL-2523.2. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

<u>Operating Experience</u>. The staff reviewed the applicant's operating experience for the ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program.

The applicant stated that plant-specific operating experience has shown that degradation has occurred. For example, the applicant has identified the following: failed tendon wires, missing or broken components found in the tendon hardware, degraded concrete in containment structure, corroded containment liner, and corrosion of penetrations inside of containment. These occurrences of degradation have been evaluated and corrective action has been taken.

The staff reviewed documented industry experience, specifically NRC Information Notice (IN) 97-10, "Liner Plate Corrosion in Concrete Containments," and IN 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments." The staff determined that the plant-specific operating experience described in the LRA is bounded by the documented industry experience discussed in the INs.

Furthermore, the applicant also stated that during preparations for the 28th-year tendon surveillance, it was discovered that the designated "common" or "control" tendons (*i.e.,* those tendons in each group that are tested every surveillance in order to establish the trend of prestress force for that group) had been retensioned during each preceding surveillance. Periodic retensioning of these tendons did not allow an accurate determination of prestress force relaxation trends. New common tendons, which had not been previously retensioned, were selected for the 28th-year surveillance. These tendons will be tested in future surveillances to establish valid prestress force trends. The NRC was advised of this situation in a letter from Mark P. Findlay (NMC) to Document Control Desk (NRC), dated June 29, 1999, "Dockets 50-266 AND 50-301 Reselection of Control Tendons in the Point Beach Nuclear Plant, Units 1 and 2."

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

<u>FSAR Supplement</u>. In LRA Section A15.2.2, the applicant provided the FSAR supplement for the ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.3 ASME Section XI, Subsection IWF Inservice Inspection Program

Summary of Technical Information in the Application. The applicant's ASME Code Section XI, Subsection IWF Inservice Inspection Program is described in LRA Section B2.1.3, "ASME Section XI, Subsection IWF Inservice Inspection Program." The applicant stated that this is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.S3, "ASME Section XI, Subsection IWF."

The applicant stated that the ASME Code Section XI, Subsection IWF Inservice Inspection Program, is credited for managing the aging effects for Class 1, 2, and 3 component supports. The primary inspection method employed is visual examination. Criteria for acceptance and corrective action are in accordance with ASME Code Section XI, Subsection IWF. Degradation that potentially compromises the function or load capacity of the supports, including bolting, is identified for evaluation. Supports requiring corrective action are re-examined during the next inspection period. The applicant stated that this program is in accordance with 10 CFR 50.55a and NRC-approved code cases and relief requests. This program is credited by the Bolting Integrity Program for the inspection of bolting and fasteners within the scope of ASME Code Section XI, Subsection IWF.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

LRA Section B2.1.3 states that the ASME Code Section XI, Subsection IWF Inservice Inspection Program is consistent with GALL AMP XI.S3, with exceptions. The ASME Code Section XI, Subsection IWF Inservice Inspection Program takes exception to the "scope of the program" program element in that, (1) the program uses the ASME Code Section XI, 98A00, whereas GALL AMP XI.S3 references the ASME Code, 1989 through 1995 Editions with Addenda through 1996, and (2) MC supports are not addressed.

The applicant stated that there are no MC supports within the scope of license renewal; therefore, it is not necessary to list inspection criteria for MC support in this AMP. As documented in the audit and review report, the staff reviewed the information provided in the LRA and held discussions with the applicant's technical staff. The staff confirmed the absence of MC falling within the scope of license renewal. On this basis, the staff found this exception acceptable.

The ASME Code Section XI, Subsection IWF Inservice Inspection Program also takes exception to the "scope of the program" and "detection of aging effect" program elements in that the IWF-2420 successive inspection criteria have been modified to sequence the examinations established in the previous inspection interval to be changed in a manner that reduces scaffold, insulation, and radiation exposure.

In its response to OI B2.1, under the ASME Code, Section XI, Subsections IWB, IWC, and IWD, and Subsections IWE and IWL, by letter dated July 5, 2005, the applicant withdrew the alternatives listed below. These alternatives affected exceptions initially credited under Subsection IWF.

- Altering the Date of the Start of the Fourth Inspection Interval
- Use of ASME Code, Section XI, 1998 Edition with Addenda through 2000
- Successive Inspections (Code Case N-624)

The applicant clarified in its letter that these alternatives are not exceptions to the GALL Report as they are either administrative and did not affect aging management or the AMR aging effect was managed by another aging management program cited in the LRA. The staff found each of the bases identified in the applicant's RAI response acceptable and agreed that these alternatives are not exceptions to the GALL Report. The staff found the withdrawal of these alternatives acceptable. Further discussions on remaining exceptions related to Subsections IWB, IWC, and IWD and Subsections IWE and IWL are documented in SER Sections 3.0.3.2.1 and 3.0.3.2.2, respectively.

In LRA Section B2.1.3, the applicant stated that its ASME Code Section XI, Subsection IWF Inservice Inspection Program is consistent with GALL AMP XI.S3, with enhancements. The applicant stated that, for the "parameters monitored or inspected" program element, enhancements include revising existing implementing documents to include cracks as recordable conditions for component supports. The staff considered this type of enhancement to be an administrative enhancement that does not require staff review.

<u>Operating Experience</u>. The staff reviewed the applicant's operating experience for the ASME Code Section XI, Subsection IWF Inservice Inspection Program. The applicant stated that it performed a review of industry and plant-specific operating experience. IN 80-36 notified utilities of the potential for SCC of high-strength component support bolts. High-strength (>150 ksi yield) component support bolting is used in pinned connections associated with the steam generator (SG), reactor coolant pump, and reactor vessel supports and is loaded only in shear. SCC of these bolts is not a concern because the bolts have no preload stress and are not located in an aggressive environment.

The applicant also stated that the most common relevant condition discovered by the ASME Code Section XI, Subsection IWF Inservice Inspection Program has been loose fasteners in supports. Loose fasteners are a maintenance issue rather than a sign of age-related degradation. The applicant also stated that, to date, these examinations have been effective in managing aging effects for ASME Code Class 1, 2, and 3 component supports.

Furthermore, the applicant stated that two pipe supports in the auxiliary feedwater pump room were found with gaps between the baseplate and the concrete wall that exceeded the criteria specified in plant procedures. A condition report was issued, and an operability determination performed to evaluate the supports' capability to adequately transfer the design loads to the building structure. The operability determination concluded that the support was operable and that no further action was required; the condition report was closed. Additional information regarding the high strength bolts inspection history is documented under RAI B2.1.4-3 of the "parameters monitored or inspected" of the Bolting Integrity Program in SER Section 3.0.3.2.4.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the ASME Code Section XI, Subsection IWF Inservice Inspection Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.3, the applicant provided the FSAR supplement for the ASME Code Section XI, Subsection IWF Inservice Inspection Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.4 Bolting Integrity Program

Summary of Technical Information in the Application. The applicant's Bolting Integrity Program is described in LRA Section B2.1.4, "Bolting Integrity Program." The applicant stated that this is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.M18, "Bolting Integrity."

The applicant stated that the Bolting Integrity Program is credited for managing the aging effects associated with bolting through the performance of periodic inspections. The program also includes repair/replacement controls for ASME Code Section XI related bolting and generic guidance regarding material selection, thread lubrication, and assembly of bolted joints. The program considers the guidelines delineated in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," for a Bolting Integrity Program; EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Plants," (with the exceptions noted in NUREG-1339) for safety-related bolting; and EPRI TR-104213, "Bolted Joint Maintenance & Application Guide," for nonsafety-related bolting.

The Bolting Integrity Program credits seven separate AMPs for the inspection of bolting. The seven AMPs are: (1) ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, (2) ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program, (3) ASME Code Section XI, Subsection IWF Inservice Inspection Program, (4) Systems Monitoring Program, (5) Structures Monitoring Program, (6) Reactor Vessel Internals Program, and (7) Periodic Surveillance and Preventive Maintenance Program.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.4 regarding the applicant's demonstration that the Bolting Integrity Program will ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Bolting Integrity Program against the AMP elements found in the GALL Report, SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1, and focused on how the program manages aging effects through the effective incorporation of 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience). The Bolting Integrity Program takes exceptions to the following program elements: (1) scope of the program, (2) preventive actions, (4) detection of aging effects, (5) monitoring and trending, and (6) acceptance criteria.

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

LRA Section B2.1.4 states that the Bolting Integrity Program is consistent with GALL AMP XI.M18, with enhancements. The applicant stated that, for the "parameters monitored or inspected" program element, enhancements include revising existing implementing documents to include specific inspections for the aging effects being managed by this program. The staff considered this type of enhancement to be an administrative enhancement that does not require staff review.

(1) Scope of the Program - The applicant stated that the Bolting Integrity Program covers all bolting and fasteners within the scope of license renewal, including safety-related bolting, bolting for Nuclear Steam Supply System (NSSS) component supports, bolting for other pressure-retaining components, and structural bolting. The Bolting Integrity Program manages the aging effects associated with bolting through the performance of periodic inspections. The program also includes repair/replacement controls for ASME Code Section XI-related bolting and generic guidance regarding thread lubrication and assembly of bolted flanges.

The GALL Report recommendations and guidelines for a comprehensive Bolting Integrity Program that encompasses all safety-related bolting are delineated in NUREG-1339. The applicant's program considers the guidelines delineated in NUREG-1339 for a Bolting Integrity Program, EPRI report NP-5769 (with the exceptions noted in NUREG-1339) for safety-related bolting, and EPRI report TR-104213 for the bolting. Due to the broad scope of the EPRI documents, the applicant indicated that the Bolting Integrity Program uses them as reference information and guidance only. The applicant's use of these documents is discussed in the preventive actions section below.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - The applicant stated that the program takes the following exceptions to the GALL AMP XI.M18:

- In lieu of checking bolt torque and uniformity of gasket compression during the initial inservice inspection (ISI) after assembly, these parameters may be checked as part of maintenance activities.
- Enhancements to the existing plant implementation documents dealing with bolted joints will be made to incorporate recommendations as deemed appropriate based upon review of NUREG-1339, EPRI NP-5769, and EPRI TR-104213.

Checking Bolt Torque and Uniformity of Gasket Compression. As a preventive action, the GALL Report indicates that initial ISI of bolting for pressure-retaining components after assembly should include a check of the bolt torque and uniformity of the gasket compression after assembly. The applicant indicated that these parameters may be checked as part of maintenance activities, but the initial ISI would only include an inspection for leakage from reactor coolant system (RCS) components.

The staff's review of LRA Section B2.1.4 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 RAIs as discussed below.

RAI B2.1.4-1. In RAI B2.1.4-1, dated February 7, 2005, the staff requested the applicant to describe the maintenance procedures that are used to check bolt torque and uniformity of gasket compression. Additionally, the staff requested the applicant to provide the frequency of the maintenance activity.

In its response, dated March 4, 2005, the applicant stated the following:

> Maintenance Instruction (MI) 32.1 provides generic guidance regarding bolt torque values and uniform gasket compression on typical bolted joints and is used in the development of the work control package if requirements are not otherwise specified by drawings or equipment technical information. Note that the majority of bolted joints at PBNP are designed to ensure the uniformity of gasket compression by the use of metal-to-metal joints, either through the use of a gasket crush ring or a gasket recess in the joint flange. The frequency of the maintenance activity is dependant on the need to disassemble and reassemble the joint as part of a corrective maintenance activity of the joint itself or to support corrective or periodic maintenance of associated components.

Since bolt torque and uniformity of gasket compression are checked in accordance with a plant maintenance instruction, the staff concluded that bolt torque and uniformity of gasket compression do not need to be checked during initial ISI. The staff's concerns described in RAI B2.1.4-1 are resolved.

NUREG-1339, EPRI NP-5769, and EPRI TR-104213. GALL AMP XI.M18 indicates that it relies on recommendations for a comprehensive Bolting Integrity Program, as delineated in NUREG-1339, and industry recommendations, as delineated in the EPRI

NP-5769, with the exceptions noted in NUREG-1339 for safety-related bolting. The GALL Report relies on industry recommendations for comprehensive bolting maintenance, as delineated in the EPRI TR-104213 for pressure-retaining bolting and structural bolting. The applicant indicated that enhancements to the existing plant implementation documents dealing with bolted joints will be made to incorporate recommendations as deemed appropriate based upon review of NUREG-1339, EPRI NP-5769, and EPRI TR-104213. The applicant has not identified exceptions to these NUREG and EPRI documents.

RAI B2.1.4-2. In RAI B2.1.4-2, dated February 7, 2005, the staff requested the applicant to provide specific exceptions to the program. The staff should be informed of, and approve, specific exceptions to the bolting recommendations in these NUREG and EPRI documents. The applicant must provide this information for staff review and approval prior to issuance of the extended license. This was identified as open item (OI) B2.1.4-2.

The staff's concern was referred to the Region III staff, who performed its AMR/AMP onsite inspection during the weeks of March 7 and 21, 2005. In its response to OI B2.1.4-2, by letter dated April 8, 2005, the applicant provided specific exceptions to EPRI NP-5769. The applicant's discussion and the staff's evaluation are documented below.

Thread Lubrication. The applicant stated that NMC does not utilize a single lubricant for all bolting material on site because of multiple needs and vendor recommendations. The use of thread lubricants is controlled via the use of Maintenance Instructions (MI) 32.1, "Flange and Closure Bolting," and MI 29.1, "Use of Thread Lubricants and Sealants." These documents have been reviewed and will be revised as necessary to more clearly state that lubricants containing molybdenum disulfide should not be used unless evaluated on a case-by-case basis with consideration given for the potential of SCC.

EPRI NP-5769 recommends that utilities use a single lubricant for all bolting materials onsite to facilitate control. Lubricants containing molybdenum disulfide are not recommended, except on a case-by-case basis. The staff considers the use of multiple lubricants acceptable because the use of lubricants is controlled through maintenance procedures. The applicant's clarification of the use of molybdenum disulfide meets the intent of the EPRI recommendation.

Locking Devices for Component Supports. The applicant stated that this section describes design requirements for component support threaded fastener locking devices and specifically precludes the use of disk or helical spring locking devices. These requirements were derived from ASME Section III, Subsection NF. PBNP is not an ASME Section III code of record plant and will not apply these specific requirements but will continue to use locking devices per the design codes, standards, and specifications applicable to PBNP.

The code of record for PBNP piping is ASA B31.1 - 1955 Edition for the RCS piping and USAS B31.1 - 1967 Edition for other piping. B31.1 - 1967 Edition, Section 121.1.3, "Hanger Adjustments," and B31.1 - 1955 Edition, Section 605(f) contain a specific requirement for suitable locking devices on hanger screw thread (and equivalent) adjustments. NMC will continue to comply with these code requirements for PBNP. Bolt preload, as a technique for a locking device for threaded fasteners, is employed at PBNP in certain applications. High strength bolting design and installation was in accordance with AISC-Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings, (April 1963). Section 1.23, "Fabrication," and specifically Section 1.23.5, "Riveted and High Strength Bolted Construction-Assembling," details the requirements for bolt tensioning and hence fastener locking. High strength structural bolting at PBNP is in accordance with ASTM A325 and A490.

ASME Section III, Subsection NF - Supports, incorporates the requirements of high strength bolting from the AISC specification. Even though PBNP is not an ASME Section III designed plant for piping, PBNP meets the design requirements for preloading for high strength fasteners as used in component support design and installation.

Based on the clarification provided above, the staff found this acceptable.

Torquing Requirements for Quenched and Tempered Bolting. The applicant stated that the recommended torque values specified in Table 1-2 of the EPRI document were derived from page 383 of the Crane Co. Catalogue No. 60 published in 1960, and applies a +/- 10 percent tolerance on the torque values. NMC currently uses the guidance provided in MI 32.1 and Form PBF-9142, which contains information that is derived from a more recent Crane Co. catalog and applies a +/- 5 percent tolerance on the torque values. The torque values in the more recent guidance differ slightly from the earlier information for the larger diameter bolting-material. The torque values in MI 32.1 and Form PBF-9142 are used by maintenance personnel for flange and closure bolting unless torque values are imposed by other documents such as drawings, applicable specifications, or instruction manuals.

The staff considers the use of alternative torque values acceptable because they are controlled by maintenance procedures and are derived from industrial standards.

Flanged Joints with Flexitallic Gaskets or Soft Rubber, or Other Pliable Gaskets. The applicant stated that the first paragraph in this section of NP-5769 states that the torque values specified in Table 1-2 are also recommended for soft, rubber, and other pliable gaskets. At PBNP, NMC does not normally use bolt torque values as the controlling factor for pressure-retaining joints that use rubber gasket material over the full face of the joint (*i.e.*, do not have a metal-to-metal interface to control compression) unless specifically evaluated or recommended for the application. Use of the torque values specified in Table 1-2 of Volume II of EPRI NP-5769 may result in over compression of rubber gasket material. Appropriate tightening of closure bolts for pressure-retaining joints that use full face rubber gasket material is controlled by verifying the evenness of the gasket compression without over compressing the gasket material. This is similar to the "skill-of-the-craft" guidance provided in Section 3.7.1 of EPRI TR-104213.

Based on the clarification provided above, the staff found this acceptable because the applicant is using alternative industry guidance in EPRI TR-104213.

Procedures and Personnel. The applicant stated that NP-5769 states that NDE personnel performing or interpreting NDE, including visual examinations specified by codes, are qualified to SNT-TC-1 A-1975. PBNP uses NDE personnel qualified and certified to later revisions of SNT-TC-1A or ANSI/ASNT CP-189, which is more restrictive than SNT-TC-1A. This is discussed in the 1998 Edition through 2000 Addenda of ASME Section XI, IWA-2310. NMC will continue to follow the requirements of 10 CFR 50.55a or request relief, as necessary for PBNP. The referenced section of Volume II, Section 1 of EPRI-5769 invokes the application of latter editions of various ASME Codes, including Section XI.

Based on the clarification provided above, the staff found this acceptable because the applicant will meet the requirements of 10 CFR 50.55a.

Re-Use of Bolting Material. The applicant stated that this section of NP-5769 states that any bolt or nut tightened by the turn-of-nut method shall not be reused. NMC will clarify this requirement to apply only to component support bolting installed in accordance with AISC or similar design specifications in which the turn-of-nut method may result in the bolting material being stressed beyond yield.

Based on the clarification provided above, the staff found this acceptable.

Non-ASME Section III Bolting Material. The applicant stated that PBNP is a B31.1 plant and does not specify ASME Class III requirements for non-ASME Class III bolting. NMC does however require a Certified Material Test Report (CMTR) or a Certificate of Conformance (COC) for the procurement of all QA bolting material. Augmented quality (AQ) bolting is procured to catalog description/part number or material specification and is verified to meet those standards through generation of a purchase order to an approved vendor; reviewing the vendor supplied packing lists, labeling and supplemental documents; and by performing a visual examination consisting of part number verification, marking verification and dimensional verification as applicable.

EPRI NP-5769 indicates that Non-ASME Section III Bolting Material should be procured with a manufacture's certification that the material is in accordance with the material specification, type, grade, or class, and heat-treated condition, as applicable. The staff found that this clarification is consistent with the procurement requirements of EPRI NP-5769 and, therefore, acceptable.

Hardness Test. The applicant stated that NMC does not perform hardness tests of random samples of bolting material during receipt inspection at PBNP. With few exceptions, (*e.g.*, Hilti Quickbolts), safety-related bolting used at PBNP is provided with a CMTR. NMC reviews the CMTR and confirms that either the hardness or actual tensile or proof load test falls within the acceptable range for the material. Hardness, tensile strength, and proof load information is not provided if the material is procured only with a COC. NMC would only perform hardness tests if the provided information was suspect based on site or industry operating experience.

EPRI NP-5769 recommends that the utility hardness test a random number of items from each lot of safety-related fasteners, as part of the receipt or preinstallation inspection. The hardness test is a check to ensure that the fasteners have not been heat-treated to a hardness that is not within specification or that the alloying elements (*i.e.* carbon) do not exceed specification. If hardness is too high, fasteners could be susceptible to stress corrosion cracking. If the hardness is too low, the fasteners may not meet minimum mechanical properties. This test should be performed prior to installation to ensure the fasteners meet hardness specification requirements. This is typically done by licensees as part of their incoming quality assurance program.

Subsequently, the staff indicated to the applicant that PBNP should meet the recommendations for random hardness testing in EPRI NP-5769. In its response, dated July 19, 2005, the applicant withdrew this exception and stated that PBNP will conduct hardness testing of random samples of bolting materials as part of the receipt inspection process as recommended in EPRI NP-5769 during the period of extended operation at PBNP. Based on this clarification, the staff found this acceptable.

The staff evaluated the applicant's response to RAI B2.1.4-2 and its specific exceptions to EPRI NP-5769 and found them acceptable. The staff's concern is resolved and, therefore, OI B2.1.4-2 is closed.

(3) Parameters Monitored or Inspected - The applicant stated that the inspection program for high strength (≥150 ksi yield strength) bolting in NSSS component supports associated with the SG, reactor coolant pump and reactor vessel supports would be inspected and tested in accordance with ASME Code requirements; but would not be inspected and tested in accordance with the additional recommendations in GALL AMP XI.M18 for high strength bolts. GALL Report XI.M18 indicates that all high strength bolting used in NSSS component supports should be inspected to the requirements for ASME Code Class 1 components, examination category B-G-1. ASME Code Class 1 components, examination category B-G-1 requires all bolting to be volumetrically examined. The ASME Code requires NSSS bolting to be visually examined (VT-3 examination); but does not require a volumetric examination of the bolting. The applicant indicated that volumetric examinations of the high strength bolting in NSSS component supports are not necessary because these bolts are not susceptible to SCC because they are loaded only in shear, they have no preload and they are not located in an aggressive environment.

RAI B2.1.4-3. In RAI B2.1.4-3, dated February 7, 2005, the staff requested the applicant to provide data that demonstrate that the bolting, loaded within the maximum shear stress, would not be susceptible to SCC. Additionally, the staff requested the applicant to identify the inspection history for its bolts that demonstrate that they are not susceptible to SCC.

In its response, dated March 4, 2005, the applicant stated the following:

> ... A review of plant drawings and specifications for the supports of Class 1 components was performed to determine the design of the connection and bolt preload requirements. A490 bolting/material is used in two types of applications for the supports of Class 1 components. It functions as a bolt in bolted connections and as a pin in pinned connections (bearing-type). The PBNP support drawings detail the use of jam nuts in combination with the bolt nuts for many of the pins and embedded anchor bolts. The use of jam nuts clearly

signify that preload was to be excluded. The conclusion drawn is that bolt preload was not intended and that the bolts were not placed in a state of high tensile stress. As a point of reference, the AISC allowable working stress for A490 fasteners is 54 ksi in tension and 32 ksi in shear (threads excluded from shear plane). The bolted connections were most likely tightened (preloaded) in accordance with AISC specifications.

Contaminants such as sulfates, fluorides, or chlorides can provide the necessary environment for SCC. Materials respond differently to environmental (aqueous mediums) and stress conditions. The general environment in a reactor containment building is closely controlled to exclude sulfate, fluoride, or chloride contaminants. Moist environments and effects of boric acid corrosion are avoided. In the past SCC in the presence of bolt lubricants has been a problem. Molybdenum disulfide (MoS_2) has experienced decomposition, resulting in the introduction of H_2S contaminants needed to promote SCC failure. NMC takes care in the selection of lubricants to preclude lubricant-induced SCC.

Plant-specific operating experience history for the supports of Class 1 components is also important information. Currently, 1998 Edition with Addenda through 2000 of ASME Code Section XI is required to be implemented at PBNP. Under Examination Category F-A, item number F1.40, the bolting on these component supports are examined periodically. The inspection method is VT-3. Personnel are trained and qualified in accordance with ANSI-ASNT CP-189 (IWA-2310). This qualification requires written tests to prove the examiner has the knowledge required for examinations and a practical test to ensure they understand the components they are examining.

The requirement is to examine 100 percent of the supports. For components other than piping, within a system of similar design, function, and service, the supports of only one of the multiple components are required to be examined. This would mean the supports of one RCP and one steam generator, and the reactor pressure vessel (RPV), would be examined each ten-year interval. The examination requirement includes all bolted connections to the component, to the building structure, and any intervening elements. The acceptance standards (IWF-3410) state that any deformations or structural degradations of fasteners, springs, clamps, or other support items, and missing, detached, or loosened support items are unacceptable for continued service until repaired, replaced, or accepted by evaluation or test. If the acceptance criteria cannot be met, then additional examinations (IWF-2430) shall be performed. This would include the immediately adjacent component supports and additional supports within the system, equal in number and of the same type and function as those scheduled for examination during the inspection period (periods usually include two outages). This would require PBNP to look at the supports on the other RCP and steam generator.

The Boric Acid Program also takes a critical look at bolting. Whenever boric acid is found, the requirement is to look at the flow path of where the boric acid has traveled. If boric acid is found on bolting, the boric acid will be removed and a visual examination performed on the fasteners to determine if any degradation has occurred. NMC will follow plant procedures for repair or replacement if the evaluation determines the bolting is not acceptable.

The inspection history results are reported in the applicant's response to RAI B2.1.4-3. Since 1991, reactor coolant pump supports and SG supports have been inspected on numerous occasions. No recordable indications have been observed. The Region III staff, on their AMR/AMP onsite inspection during the weeks of March 7 and 21, 2005, will confirm that there were no failures of high strength bolts. This was identified as confirmatory item (CI) B2.1.4-3.

The inspection history for high strength bolts was verified by the Region III staff, during their AMR/AMP onsite inspection. Section D.1 of the DRS Aging Management Inspection Report, dated May 2, 2005, states the following:

> The inspectors requested specific searches of the plant specific operating experience and verified that the applicant performed adequate historic reviews to determine aging effects. The inspectors determined that the licensee did not have any documented occurrences of failure in high strength structural bolting. During plant walkdowns, the inspectors specifically looked for cases where structural bolting appeared loose, missing or failed; no problems were identified. Following submittal of the LRA, the licensee did identify two cases where component bolts were replaced. In one case, the licensee discovered a longitudinal crack in a reactor coolant pump seal package bolt. The licensee replaced the bolt and sent the cracked bolt off for laboratory analysis. The crack was determined to be a manufacturing defect and not related to aging degradation. The second case was replacement of all the bolting on the Unit 2 pressurizer after indications were identified during the inservice inspection. The indication disposition report and a subsequent corrective action procedure (CAP) document analyzed the indications and determined that the majority of the indications were minor, appeared most likely due to normal installation and removal of the bolts, and did not affect the integrity of the bolting. However, one bolt had two minor "crack like" indications. The licensee did not determine the cause of these indications; however as the bolts were replaced and no pressurizer leakage had occurred during the previous operating cycle, the inspectors concluded that the licensee's inservice inspection program had adequately addressed the issue.

The staff found this acceptable since the inspectors confirmed that the applicant did not have any documented occurrences of failure in high strength structural bolting. The staff's concern is resolved and, therefore, CI B2.1.4-3 is closed.

Since the applicant has not observed any degradation of bolting using ASME Code inspection methods and frequency, the staff concluded that the applicant demonstrated that the bolting has not been susceptible to SCC, that volumetric examination of the high strength bolting in NSSS component supports is not necessary, and that the applicant's program will be successful in monitoring degradation of high strength component support bolting during the period of extended operation.

The staff confirmed that the "parameters monitored or inspected program" element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - The applicant stated that this element is consistent with GALL Report XI.M18, except that high strength NSSS component support bolting would not be inspected and tested in accordance with the recommendations in GALL Report XI.M18 and that structural bolting would not be subjected to the augmented testing discussed in GALL Report XI.M18.

In addition, the applicant indicated that PBNP uses the ASME Code Section XI 98A00 instead of the ASME Code 95A96 referenced in GALL Report XI.M18. Since 10 CFR 50.55a endorses the ASME Code 98A00, Section XI, the staff concluded that it is acceptable to use the ASME Code 98A00, Section XI.

With respect to the discussion covering the structural bolting and fasteners under the "detection of aging effects" program element, the applicant elected to take exceptions to the corresponding NUREG-1801 AMP element and stated that, "Components that are within the scope of license renewal and are not within the scope of the ASME Code Section XI ISI programs are visually inspected for signs of degradation and are only inspected more closely when signs of degradation are present." The applicant further indicated that, "PBNP does not plan to perform additional tests such as hammer tests, in situ ultrasonic tests, or proof tests by tension or torquing," without providing a plant-specific basis for the exceptions taken.

RAI B2.1.4-6. In RAI B2.1.4-6, dated February 23, 2005, the staff requested the applicant to provide the following information:

- In the context of PBNP's implementation of its aging management of in-scope structural bolting and fasteners, explain with examples the definition or meaning of the phrase: "when signs of degradation are present."
- List PBNP's basis for taking the above stated exceptions to the corresponding NUREG-1801 AMP element, including a discussion of past plant-specific operating experience and/or inspection data-based justifications.
- Given a discovery or an identification of a credible or a significant degradation of in-scope structural bolting or fastener(s) meeting the definition of the first bullet above, please explain the specific steps that would be taken and a list of applicable plant-specific program(s) or procedures that will be used, per PBNP's current AMP(s) for structural bolting and fasteners, to dispose in a timely manner the identified degraded event.

In its response, dated March 15, 2005, the applicant stated that the Bolting Integrity Program credits the Structures Monitoring Program and the ASME Code IWF Program for the inspection of structural bolting. As described in LRA Section B2.1.20 under "Parameters Monitored or Inspected," the types of degradation addressed by the visual inspection include corrosion, rust, looseness, physical damage or deformation, lack of full thread engagement, missing or out of place parts, and improper washers. The applicant indicated that visual inspection is considered adequate to detect the types of degradation. These visual inspections apply to ASME Code (IWF) and non-ASME Code structural bolting. As discussed in the applicant's clarification to RAI B.2.1.4-3 in its letter dated March 4, 2005, PBNP has not identified any high strength structural bolting susceptible to cracking. There have been no incidents of loss of intended function of a component or system due to structural bolting degradation, and the Structures Monitoring Program requires that significant degradation of structural bolting will be documented and entered into the PBNP corrective action program. As part of the corrective action program process, degradation noted in these inspections will be evaluated, and appropriate actions relative to the significance of the degradation will be taken. Appropriate actions may include replacement, increased monitoring, or both.

The staff found the above response acceptable. The applicant (1) adequately explained key signs of degradation in structural bolting, (2) indicated that there have been no incidents of loss of intended function of a component or system due to structural bolting degradation, (3) asserted, based on its operating experience, that performing visual inspection is adequate to detect the types of degradation described above, and (4) confirmed that its Structures Monitoring Program requires that significant degradation of structural bolting will be documented and entered into the corrective action program. As part of the corrective action program process, degradation noted in these inspections will be evaluated, and appropriate actions relative to the significance of the degradation will be taken. Therefore, the staff's concerns described in RAI B2.1.4-6 are resolved.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - The applicant stated that this element is consistent with GALL Report XI.M18, except that the frequency of inspection of leaking pressure-retaining components (not covered by ASME Code Section XI) will not be in accordance with GALL Report XI.M18. GALL Report XI.M18 indicates that these components should be inspected daily. If they have leaks and if the leak rate does not increase, the inspection frequency may be decreased to weekly or biweekly. The applicant indicated that the frequency of inspection of leaking pressure-retaining non-ASME Code components will be in accordance with the plant maintenance and/or corrective action process.

<u>RAI B2.1.4-4</u>. In RAI B2.1.4-4, dated February 7, 2005, the staff requested the applicant to identify how the plant maintenance and/or the corrective action program determines the frequency of inspection of these components. Additionally, the staff requested the applicant to identify if any of these components have ever lost their intended function prior to repair.

In its response, dated March 4, 2005, the applicant stated the following:

> Documentation of leaking components is done via the corrective action process or the corrective maintenance process. All corrective action and corrective maintenance requests that have the potential to affect equipment operability are reviewed by a Senior Reactor Operator. The condition is evaluated and the appropriate actions relative to the significance of the condition are taken. The

appropriate actions may include an expeditious repair, scheduled future repair with periodic monitoring until the repair is completed, scheduled future repair with no periodic monitoring, or no specific actions. Significant increases in leakage would most likely be noted via operator rounds during normal plant operations and/or observation of reduction of inventory in closed systems or increased flows in various drainage systems. As noted in Section B2.1.4 of the license renewal application, a review of plant-specific operating experience identified no instances of loss of intended function of a component or system due to fastener degradation.

The staff agreed that the frequency of inspection of non-ASME Code bolting should be in accordance with the applicant's corrective action process or the corrective maintenance process because this program has proven successful. The staff's concerns described in RAI B2.1.4-4 are resolved.

The staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - The applicant stated that this element meets the intent of the corresponding element in GALL Report XI.M18. The applicant indicated that cracks in component support bolting will be repaired when scheduled as part of the plant maintenance and/or corrective action process. GALL Report XI.M18 indicates that cracked bolts in component supports should be replaced immediately.

RAI B2.1.4-5. In RAI B2.1.4-5, dated February 7, 2005, the staff requested the applicant to identify how the plant maintenance and/or corrective action program determines when cracked component support bolting is replaced. Additionally, the staff requested the applicant to identify if these components have ever lost their intended function prior to repair.

In its response, dated March 4, 2005, the applicant stated the following:

> The corrective action process is used upon discovery of cracked bolting in a support that is in-scope in accordance with 10 CFR 54.4. As a result an immediate operability determination for cracked support bolting is made by a Senior Reactor Operator. As part of this operability determination an Operability Recommendation can be requested from Engineering to further document the support's functionality and operability. This operability determination process is used for any corrective action or corrective maintenance documented degradation that has the potential to affect equipment operability. The corrective action process will ensure the appropriate response including shutdown of operating units if necessary to comply with PBNP Technical Specifications, other CLB requirements or to establish the conditions necessary to allow the repair.
>
> The degradation documented by the corrective action process for an operable support with a cracked bolt will be evaluated and appropriate priority set for repair or replacement. In all cases, the appropriate response for cracked

support bolts is to initiate actions in accordance with PBNP's corrective action process, which includes corrective maintenance.

As noted in Section B2.1.4 of the license renewal application, a review of plant-specific operating experience identified no instances of loss of intended function of a component or system due to fastener degradation.

The staff agreed that the plant maintenance and/or corrective action process is expected to be adequate for scheduling the repair of cracked component support bolting because this process has been proven successful. The staff's concerns described in RAI B2.1.4-5 are resolved.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.6. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - The applicant stated that a review of industry operating experience revealed numerous instances of primary pressure boundary degradation. There have been various NRC communications including information notices, bulletins, and generic letters on bolting degradation. Most instances of degradation fall into two categories: (1) boric acid corrosion caused by leakage at mechanical joints; and (2) degradation of high strength bolting caused by stress corrosion cracking. General corrosion of bolting and fasteners has also occurred for structural bolting located in a humid environment.

The applicant stated that plant-specific operating experience includes boric acid wastage on one body-to-bonnet check valve stud. General corrosion was also found on structural steel bolting. There were also a few instances of improper bolting material and torque values being used. There were no incidents of loss of intended function of a component or system due to fastener degradation.

Furthermore, the applicant stated that a review of NRC inspection reports, quality assurance (QA) audit/surveillance reports, and self-assessments, since 1999, revealed no issues or findings that could impact the effectiveness of the Bolting Integrity Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

During the audit, the staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Bolting Integrity Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

FSAR Supplement. In LRA Section A15.2.4, the applicant provided the FSAR supplement for the Bolting Integrity Program. The staff reviewed this section and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found this section of the FSAR supplement meet the requirements 10 CFR 54.21(d).

Conclusion. On the basis of its review, the above discussed RAI responses, and its audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.5 Boraflex Monitoring Program

Summary of Technical Information in the Application. The applicant's Boraflex Monitoring Program is described in LRA Section B2.1.5, "Boraflex Monitoring Program." The applicant stated that this is an existing program. As modified by letter dated April 1, 2005, the applicant stated that the program is consistent, with enhancements, with GALL AMP XI.M22, "Boraflex Monitoring."

The applicant stated that the Boraflex Monitoring Program is credited for managing the aging effects of a reduction of neutron absorption capabilities due to a change in material properties (*i.e.*, shrinkage, gap formation, and boron dissolution) resulting from gamma irradiation and a convective aqueous environment for the Boraflex material in the spent fuel racks. This program provides for blackness testing and areal density measurements of the Boraflex material in the spent fuel storage racks to confirm the in-service Boraflex performance. In addition, the applicant stated that tracking of the spent fuel pool (SFP) silica levels provides a qualitative indication of boron carbide loss. Neutron attenuation or blackness testing will be performed to determine gap formation, while areal density measurements will be used to ascertain the physical loss of boron carbide. Monitoring by analysis of criticality will also be performed to assure that the required 5 percent subcriticality margin is maintained. Based on the results of these inspections and analysis, the applicant stated that appropriate measures will be taken to ensure the Boraflex will continue to perform its intended function. This program addresses the concerns described in NRC Generic Letter (GL) 96-04,"Boraflex Degradation in Spent Fuel Pool Storage Racks."

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In LRA Section B2.1.5, the applicant stated that its Boraflex Monitoring Program is consistent with GALL AMP XI.M22, with exceptions. The Boraflex Monitoring Program takes exception to the "detection of aging effect" program element such that for certain accelerated samples tests, the applicant performs these tests at a minimum frequency of five years. GALL AMP XI.M22 recommends that certain accelerated samples be tested every two years.

The applicant stated that tests are conducted as follows: Two SFP storage locations had received freshly discharged spent fuel assemblies each refueling for approximately 9 years, which caused accelerated cumulative exposure levels to the bordering Boraflex panels. Four of these panels are tested during each scheduled surveillance. The results of the Boraflex areal density testing and Boraflex panel blackness testing are evaluated as part of the Boraflex Monitoring Program to determine if a change in test frequency or methodology is warranted.

As documented in the audit and review report, the applicant clarified the lack of accelerated individual sample testing. The applicant stated that in April 1989, PBNP submitted a surveillance program to the NRC, which was approved in February 1990, establishing blackness testing on 10 full-length Boraflex panels. Four of the panels included accelerated exposure, having received freshly discharged fuel assemblies during the previous 9 years, thereby receiving an accelerated gamma dose of 1.5E10 rads, which is equivalent to that received by the average panel in 30 years. Subsequent Boraflex panel blackness testing has been performed and completed in August 1991, September 1996, and August 2001.

PBNP's CLB is such that the plant does perform testing of "accelerated samples"; however, as noted above, a number of full-length panels are subjected to accelerated exposure.

The GALL Report states that the results based on test coupons have been found to be unreliable in determining the degree to which the actual Boraflex panels have been degraded. The staff believes that this indicates that the accelerated samples are of limited value to an AMP. Based on this statement and on the applicant's testing of intentionally high exposure full-length panels, the staff concluded that testing of "accelerated samples" is not required to provide reasonable assurance that aging effects will be appropriately managed in light of the blackness testing of full-length high-flux Boraflex panels during the period of extended operation. The staff further concluded that using the above exceptions is acceptable and ensures that the effects of aging will be managed in such a way that the intended functions of the affected SCs will be maintained consistent with the CLB for the period of extended operation.

In LRA Section B2.1.5, the applicant stated that its Boraflex Monitoring Program is consistent with GALL AMP XI.M22, with enhancements. The applicant stated that, for the "parameters monitored or inspected" and "detection of aging effect" program elements, enhancements include creation of (1) a new procedure to perform and control Boraflex areal density and blackness testing and (2) a new procedure for trending and analysis of the results of the SFP silica sampling by using the EPRI RACKLIFE predictive code or its equivalent, and determination of panels with "accelerated" exposure during the period of extended operation. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

The applicant discusses its time-limited aging analyses (TLAA) for the spent fuel storage rack boraflex in LRA Section 4.6. In its TLAA analysis, the applicant committed to perform areal density and blackness tests on certain accelerated Boraflex panels during the period of extended operation once every 2 years. The staff's evaluation of this TLAA is documented in SER Section 4.6.

Operating Experience. The staff reviewed the applicant's operating experience for the Boraflex Monitoring Program.

The applicant stated that experience with Boraflex panels indicates that coupon surveillance programs are not reliable. Therefore, Boraflex integrity is measured and correlated, through a predictive code, with the silica levels in the pool water during the period of extended operation. The applicant stated that these actions provide reasonable assurance that degradation of Boraflex sheets is adequately monitored so that appropriate actions can be taken in a timely manner if significant loss of neutron-absorbing capability is occurring.

The applicant also stated that the latest inspection of the SFP Boraflex panels was conducted in August 2001. The results of the blackness test indicated that for the first time since the Boraflex panels have been inspected, gaps have been found in 27 panels ranging from 0.8 inch to 3.4 inches. The gaps appear to be randomly distributed along the vertical length of the Boraflex panels. A condition report was issued to monitor the condition of the Boraflex in the SFP.

The applicant's discussion of operating experience included a review of NRC inspection reports, QA audit, surveillance reports, and self-assessments since 1999, which revealed no issues or findings other than those described above that could impact the effectiveness of the Boraflex Monitoring Program.

The staff reviewed the operating experience provided in the LRA, interviewed the applicant's technical staff, and verified that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. The staff found that the applicant's program is consistent with industry expectations. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Boraflex Monitoring Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.5, the applicant provided the FSAR supplement for the Boraflex Monitoring Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with 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). The staff also reviewed the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.6 Boric Acid Corrosion Program

Summary of Technical Information in the Application. The applicant's Boric Acid Corrosion Program is described in LRA Section B2.1.6 "Boric Acid Corrosion Program." In the LRA, the applicant stated that this is an existing program that is consistent, with enhancements, with GALL AMP XI.M10, "Boric Acid Corrosion."

In LRA Section B2.1.6, the applicant stated that the Boric Acid Corrosion Program manages aging effects for SSCs as a result of borated water leakage. The program requires periodic visual inspection of systems that contain borated water for evidence of leakage or accumulation of dried boric acid. The program includes provisions for (a) determination of the principal location or source of the leakage, (b) examination requirements and procedures for locating small leaks, and (c) evaluations, and/or corrective actions to ensure that borated water leakage does not lead to degradation of the leakage source as well as other SSCs exposed to the leakage, including mechanical, structural, and electrical items. The applicant stated that this program complies with PBNP's response to GL 88-05. This program credits the Systems Monitoring Program for the visual inspection of other SSCs that do not contain borated water, but which may be subject to the degrading effects of any borated water leakage.

<u>Staff Evaluation</u>. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.6, regarding the applicant's demonstration that the Boric Acid Corrosion Program will ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Boric Acid Corrosion Program against the AMP elements found in the GALL Report, SRP-LR Section A.1.2.3, and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

LRA Section B2.1.6 states that the Boric Acid Corrosion Program is consistent with the GALL Report, with enhancements. The applicant stated that procedures will be revised and/or developed to identify susceptible components upon which borated water may have leaked and ensure they are inspected for degradation. The staff considered this type of enhancement to be an administrative enhancement that does not require staff review.

(1) Scope of the Program - The applicant stated that the Boric Acid Corrosion Program includes any carbon steel, low-alloy steel, or cast iron structures or components, and electrical components, on which borated water may leak. The program adheres to GL 88-05. It includes (1) determination of the leakage source, (2) examination requirements and procedures for locating small leaks, and (3) evaluations and/or corrective actions.

NRC Bulletins 2002-01, 2003-02, and NRC Order EA-03-009 provide documentation of reported industry experience concerning degradation of ASME Code Class 1 nickel-alloy partial-penetration welds, including those used to join the upper vessel head penetration nozzles to the upper reactor vessel (RV) heads of pressurized water reactors (PWRs) and those used to join the bottom-mounted instrumentation (BMI) nozzles to the lower RV heads of PWRs. The staff requested clarification regarding the list of components that are within the scope of the Boric Acid Corrosion Program and the process the applicant uses to augment the list of components within the scope of the AMP based on pertinent industry experience. The staff RAI is addressed under Operating Experience.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - The applicant stated that the preventive actions are limited to improving maintenance practices such as revising the valve packing program to improve packing techniques, performance of pre-outage walkdowns to identify those components that may require corrective maintenance, and monitoring of locations where potential leakage could occur. Timely repair of detected leakage prevents or mitigates boric acid corrosion.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - The applicant stated that visual inspections are conducted to monitor the effects of boric acid corrosion on the intended function(s) of an affected structure or component. Borated water leakage results in deposits of white boric acid crystals and the presence of moisture that can be observed by visual inspections during system walkdowns.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.3. Visual inspections are expected to ensure that borated water leaks are properly managed. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - The applicant stated that degradation of components due to boric acid corrosion cannot occur without borated water leakage. Visual inspections are frequently conducted to identify necessary repairs and minimize the potential of a leak not being discovered and developing into a larger leak. The applicant also stated that evaluations are conducted when leaks are detected.

This program also credits the Systems Monitoring Program for the visual inspection of other SSC that do not contain borated water, but which may be subject to the degrading effects of any borated water leakage.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - The applicant stated that monitoring and trending relies on visual inspections conducted during normal plant operation and when the plant is

shutdown for refueling. The program follows the guidelines in GL 88-05 and provides for timely detection of leakage by observance of boric acid crystal deposits during plant walkdowns and maintenance.

The staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.5. Trending of inspection results will be performed and will enhance the applicant's ability to detect aging effects before there is a loss of intended function. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - The applicant stated that plant procedures provide recording, evaluation, and acceptance criteria if any leakage of borated water is noted.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.6. Any anomalous indications that are signs of degradation will be evaluated by an engineer to determine material degradation. If found unacceptable, corrective measures will be implemented. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - The applicant stated that industry operating experience clearly indicates that borated water leaking from the reactor coolant system can cause significant corrosion damage to carbon steel reactor coolant pressure boundary components.

The applicant stated that a review of plant operating experience indicates that numerous work orders, condition reports/action requests, and several applicant event reports have been issued as a result of the Boric Acid Corrosion Program discovering borated water leaks and corrosion of components due to borated water leakage. A large percentage of the work orders and condition reports/action requests initiated described dried boric acid crystal deposits either on the component from which it leaked or on the floor below the leaking component. Occasionally, dried boric acid crystals were found on components located below the leaking component. Many of the work orders initiated to repair and/or investigate evidence of borated water leakage, or both, were a result of performing system walkdowns during pressure testing.

Furthermore, the applicant stated that a review of NRC inspection reports, QA audit/surveillance reports, and self-assessments since 1999 was performed. Several enhancements were made to the PBNP GL 88-05 Boric Acid Control Program as a result of an action request initiated by the nuclear oversight group. These enhancements included consolidation of the program requirements into one document, assignment of program ownership, and the addition of program references to various implementing documents. Completion of these enhancements was tracked via the corrective action program. No other issues or findings that could impact the effectiveness of the Boric Acid Corrosion Program were identified. As additional operating experience is obtained, lessons learned may be used to adjust this program.

NUREG/CR-5576, "Survey of Boric Acid Corrosion of Carbon Steel Components in Nuclear Plants," dated January 1990, summarizes borated water leakage and boric acid corrosion events that occurred in the industry prior to 1990.

Recent industry operating experience shows how severe corrosion damage to the RV head at Davis-Besse and cracking and leakage on the RV BMI penetrations at South Texas resulted in industry attention to ensuring the implementation of an effective Boric Acid Corrosion Program.

Industry experience has demonstrated that the bi-metallic partial penetration welds fabricated using Alloy 82/182 weld material in the upper RV head penetration nozzles may be susceptible to PWSCC that could induce leakage of the borated reactor coolant over time. In addition, the industry experience summarized in NRC Bulletin 2003-02 has demonstrated that the BMI nozzles of PWR-designed light-water reactors may be susceptible to PWSCC that could induce reactor coolant leakage.

The staff's review of LRA Section B2.1.6 identified an area 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.

RAI B2.1.6-1. In RAI B2.1.6-1, dated November 17, 2004, the staff requested the applicant to submit a discussion on how the NMC responses to NRC's orders and bulletins below have been used to update the component list locations and visual inspections within the scope of the Boric Acid Corrosion Program:

- NRC Bulletin 2002-01, dated March 29 and May 16, 2002,
- NRC's RAIs on Bulletin 2002-01, dated January 17, 2003,
- NRC Bulletin 2003-02, dated September 19, 2003,
- NRC Order EA-03-009, dated March 3, April 11, and April 18, 2003, and
- NRC Bulletin 2004-01, dated May 28, 2004

If the responses were used to supplement the scope of the Boric Acid Corrosion Program or other AMPs, the staff requested the applicant to identify the component locations that had been added to the scope of the program and to clarify the type of visual examinations that will be implemented on those components within the current scope of the program.

In its response, dated January 25, 2005, the applicant confirmed that (1) there are no Alloy 82/182/600 materials in the Units 1 and 2 pressurizers; and (2) industry experience from boric acid corrosion has been incorporated into the Boric Acid Corrosion AMP, in the Reactor Coolant System Alloy 600 Inspection AMP, or both. In addition, the Units 1 and 2 RPV heads were scheduled to be replaced in 2005.

On the basis of its review and RAI response described above, the staff concluded that the Boric Acid Corrosion Program will adequately manage the aging effects that have been observed at the applicant's plant.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

FSAR Supplement. In LRA Section A15.2.6, the applicant provided its FSAR supplement for the Boric Acid Corrosion Program. The applicant summarizes that the program requires periodic visual inspection of systems that contain borated water for evidence of leakage or accumulations of dried boric acid. It includes provisions for (1) determination of the principal location or source of the leakage, (2) examination requirements and procedures for locating small leaks, and (3) evaluations, corrective actions, or both, to ensure that borated water leakage does not lead to degradation of the leakage source as well as other SSCs exposed to the leakage, including mechanical, structural, and electrical items such as bolts, fasteners, piping, cable, cable trays, and electrical connectors that could cause the loss of intended function(s).

The staff reviewed the FSAR supplement and concluded that it provides an adequate summary of the program activities, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review, RAI response, and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with 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). The staff also reviewed the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.7 Buried Services Monitoring Program

Summary of Technical Information in the Application. The applicant's Buried Services Monitoring Program is described in LRA Section B2.1.7, "Buried Services Monitoring Program." In the LRA, the applicant stated that this is a new program that is consistent, with enhancements, with GALL AMP XI.M34, "Buried Piping and Tank Inspection."

In LRA Section B2.1.7, the applicant stated that the Buried Services Monitoring Program manages aging effects on the external surfaces of carbon steel, low-alloy steel, and cast iron buried components. The applicant indicated that the Buried Services Monitoring Program is consistent with GALL AMP XI.M34, "Buried Piping and Tank Inspection." This program includes (1) preventive measures, and (2) visual inspections of external surfaces of buried components for evidence of coating damage and substrate degradation to manage the effects of aging. The program scope manages aging effects for components in the following systems and structures: Emergency Power, Service Water, and Fire Protection.

The applicant indicated that enhancements to the program will include the creation of those documents needed to implement the requirements of the program for SSCs within the program scope. Enhancements are scheduled for completion prior to the period of extended operation.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.7, regarding the applicant's demonstration of the Buried Services Monitoring Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

In LRA Section B.2.1.7, the applicant described its AMP to manage loss of material due to corrosion from external environments for buried piping and tanks in the scope of license renewal. The LRA stated that this AMP is consistent with GALL AMP XI.M34, "Buried Piping and Tanks Inspection," with enhancements necessary to ensure program documentation reflects the GALL recommendations. The applicant indicated that the program includes preventive measures to mitigate degradation (*e.g.*, external coatings and wrappings) and visual inspections of the external surfaces of buried carbon steel, cast iron, and low-alloy steel components (*e.g.*, piping, tanks) for evidence of coating damage and substrate degradation. The applicant intends to perform inspections based on plant operating experience and opportunities for inspection associated with plant maintenance. The applicant stated that components are coated pursuant to industry practice prior to installation and that the coatings and wrappings would be visually examined for signs of degradation which may be indicative of a loss of material. The applicant's proposed program will rely on an inspection periodicity based on operating experience and on inspections of opportunity. In addition, the applicant indicated that inspection results would be evaluated and if necessary additional areas warranting inspection would be identified based upon the inspection results.

The staff reviewed the Buried Services Monitoring Program against the AMP elements found in the GALL Report, SRP-LR Section A.1.2.3, and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of the Program - The applicant stated that the Buried Services Monitoring Program consists of PBNP activities that manage the aging effects for components in the following systems and structures: emergency power, service water, and fire protection. The program includes preventive measures to mitigate degradation and visual inspections of the external surfaces of buried carbon steel, cast iron, and low-alloy steel components for evidence of coating damage and substrate degradation. Inspections will be performed based on plant operating experience and opportunities for inspection such as scheduled maintenance. Enhancements to the program will result in the creation of procedures to implement the program requirements.

The staff's review of LRA Appendix B2.1.7 identified an area in which additional information was necessary to complete the review of the applicant's AMR program elements. The applicant responded to the staff's RAI as discussed below.

<u>RAI B2.1.7-1</u>. The program indicates that buried components within the program scope are coated prior to installation, pursuant to industry guidance. In RAI B2.1.7-1, dated November 18, 2004, the staff requested the applicant to clarify which components within the program scope are coated.

In its response, dated January 6, 2005, the applicant stated that piping specifications used for the design and installation of service water and fuel oil piping systems specify that coatings and wrappings were to be used for buried pipe. Further, the applicant indicated that plant-specific operating experience during excavations confirmed the presence of coatings and wrapping on buried portions of these two systems. The applicant indicated that the combination of design documentation and operating experience provides reasonable assurance that these systems utilize coatings and wraps to mitigate loss of material. The staff agreed that design documents and operating experience provide assurance that the components are coated or wrapped to mitigate loss of material and that operating experience indicates that inspections of opportunity can be used to monitor potential degradation.

The applicant also addressed the fire protection piping and indicated that fire protection piping was installed pursuant to industry standard, which may have allowed installation without a coating if the soil is not aggressive. The applicant supplied only one example of operating experience related to an inspection of opportunity for post-indicating valves (PIV) in the LRA. The applicant's response indicated that the inspection of the buried fire piping was found to have a light bituminous asphaltic coating and no signs of external degradation after 14 years. The applicant also identified its understanding that the soil is not aggressive pursuant to the guidance outlined in NUREG-1801 and indicated that an aggressive environment was defined as having pH of less than 5.5, or greater than 500 parts-per-million chlorides, or greater than 1500 parts-per-million sulfates.

During a telephone conference, dated December 15, 2004, the applicant indicated that there are potentially thousands of feet of buried fire pipe at the plant and that any pipe coating was not necessarily intended to prevent corrosion of the buried piping. The applicant's RAI response included a brief summary of past excavations of fire pipe that is intended to demonstrate that inspections of opportunity occur roughly every three to four years, and past inspections have not documented any external pipe degradation.

The staff reviewed the applicant's information provided in the LRA, the RAI response discussed above, and clarifying information provided during the telephone conference. The staff believes that the information provided by the applicant on the aggressive nature of the soil is pertinent to concrete and feels that correlation was not provided why this classification for non-aggressive soil may be used regarding potential corrosion of buried carbon steel, low-alloy steel or cast iron. The staff acknowledges the frequency that fire protection piping has been excavated, but understands that documentation does not exist regarding the condition of the piping. The staff believes that the lack of a pipe coating or pipe wrap to prevent corrosion should be identified as an exception to the GALL Report. In light of the limited documented operating experience, no specific corrosion protection coating on the piping and no correlation of the aggressive nature of the soil relative to ferrous piping, the staff requested further justification pertaining to how aging of buried, potentially uncoated pipe could be adequately managed using only inspection of opportunity. The staff indicated that inspection prior to the period of extended operation would be necessary to establish an understanding of the current condition of the piping unless additional documented operating experience establishing the condition of the piping could be provided.

During a meeting on February 15, 2005, the staff indicated and the applicant agreed, that these responses required further clarification.

In its response, a clarification letter dated March 15, 2005, the applicant committed to enhance the Buried Services Monitoring Program with additional inspections. The applicant will perform an inspection of a section of buried fire pipe prior to the period of extended operation. A susceptible section of the fire protection piping will be chosen for the inspection prior to the period of extended operation. The applicant also committed to performing an inspection at least every ten years during the period of extended operation. However, an inspection of opportunity on buried fire protection piping may be substituted for these scheduled inspections. The applicant indicated that coated and wrapped piping will be inspected to identify damage of the coating or wrapping. If coating damage is identified or if the piping is uncoated the program will require that the component be further inspected for signs of degradation. The applicant indicated that if any loss of material is identified the results will be evaluated and additional locations will be inspected, as required. Evidence of component degradation will be evaluated under the applicant's corrective action program.

The staff concluded that the enhancements to the Buried Services Monitoring Program to detect loss of material of buried fire pipe are acceptable. The material condition will be evaluated prior to the period of extended operation and during extended operation based upon visual inspection of the pipe or applied coating and if unacceptable loss of material is identified the sample population will be expanded. Visual inspection of the pipe coating is consistent with GALL Report XI M.34 to detect aging of buried piping. The staff's concern described in RAI B2.1.7-1 is resolved.

The staff confirmed that the "scope of the program" program element, with enhancements, satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - The applicant stated that buried components, such as piping and tanks, are coated pursuant to industry practice prior to installation in order to protect the component outer surfaces from corrosion and selective leaching.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - The applicant stated that the program monitors parameters, such as coating and wrapping integrity, that are directly related to loss of material due to corrosion and selective leaching on the external surfaces of buried carbon steel, low-alloy steel, and cast iron components. The effects of corrosion are detectable by visual inspections, while the effects of selective leaching are detectable by visual inspections and/or hardness measurements. If there are any indications of selective leaching, or if the condition is indeterminate, a hardness test will be performed.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - The applicant stated that inspections of buried components, such as piping and tanks, at susceptible locations, are performed to confirm that coatings and wrappings are intact and can ensure that age-related degradation of external surfaces has not occurred and that the components' intended function(s) can be maintained. The periodicity of these inspections will be based on plant operating experience and opportunities for inspection such as scheduled maintenance work.

In its response to RAI B2.1.7-1, the applicant submitted a clarification letter, dated March 15, 2005, in which the applicant committed to enhance the Buried Services Monitoring Program with additional inspections. The applicant will perform an inspection of a section of buried fire pipe prior to the period of extended operation. A susceptible section of the fire protection piping will be chosen for the inspection prior to the period of extended operation. The applicant also committed to performing an inspection at least every ten years during the period of extended operation. However, an inspection of opportunity on buried fire protection piping may be substituted for these scheduled inspections. The applicant indicated that coated and wrapped piping will be inspected to identify damage of the coating or wrapping. If coating damage is identified or if the piping is uncoated the program will require that the component be further inspected for signs of degradation. The applicant indicated that if any loss of material is identified the results will be evaluated and additional locations will be inspected, as required. Evidence of component degradation will be evaluated under the applicant's corrective action program.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.4. Inspections of susceptible locations are expected to ensure management of aging effects. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - The applicant stated that the inspection results will be evaluated and used to assess the condition of the external surfaces of buried components and to identify susceptible locations that may warrant further inspections.

The staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.5. The use of previous inspection results is an appropriate method to establish monitoring and trending of susceptible locations. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - The applicant stated that evidence of coating and wrapping degradations will be documented and evaluated under the Corrective Action Program.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.6. Documentation and evaluation of coating and wrapping degradation is expected to ensure implementation of corrective actions and management of aging effects. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - The applicant stated that industry experience has shown that carbon steel, low-alloy steel, or cast iron buried components have experienced corrosion and selective leaching degradation. The critical areas appear to be at the interface

where the component transitions from above ground to below ground. This is also the area where coating and wrappings will most likely be missing or damaged. Experience shows that the combination of protective coatings and relatively non-aggressive soil conditions at PBNP serve to lessen the probability of component degradation due to corrosion. Based on this plant-specific operating experience, the implementation of the program will adequately manage the aging effect of loss of material due to corrosion and selective leaching for the period of extended operation. A review of NRC inspection reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the program.

The staff's review of LRA Appendix B2.1.7 identified areas in which additional information was necessary to complete the review of the applicant's AMR program elements. The applicant responded to the staff's RAIs as discussed below.

RAI B2.1.7-2. Related operating experience shows that a post-indicating valve was repaired in the fire protection system requiring excavation and exposing portions of the associated piping. In RAI B2.1.7-2, dated November 18, 2004, the staff requested the applicant to discuss the condition assessment of the piping. The staff also requested the applicant to provide details about the piping coating and its corrosion (or lack of corrosion).

Operating experience from a 1993 excavation where coating on 30-inch service water line and one-inch diesel fuel oil line was damaged was provided. The applicant stated that a condition report was written during the course of the excavation to repair damaged coating. The condition report indicated that no corrosion of the piping existed and that the coating was repaired.

Further, in its response dated January 6, 2005, the applicant also provided operating experience from an inspection of opportunity during repair to a fire protection system PIV. The visual inspection included piping areas that were coated, as well as areas where the base metal of the piping was exposed. This PIV had been buried for 14 years and showed no signs of corrosion.

The staff found this response acceptable, because the applicant provided adequate supporting information. Therefore, the concern described in RAI B2.1.7-2 is resolved.

RAI B2.1.7-3. PBNP has limited operating experience regarding inspections of opportunity validating the buried component degradation. The GALL Report indicates that inspection periodically is to be evaluated on a plant-specific basis. In RAI B2.1.7-3, dated November 18, 2004, the staff requested the applicant to justify why a one-time inspection of various in-scope components is not warranted to establish a basis for inspection frequency. The staff also requested the applicant to justify why inspections of opportunity will adequately manage aging.

In its response, dated January 6, 2005, the applicant stated that although the Buried Services Monitoring Program is a new program, PBNP has almost 34 years of operating experience with buried components. During that time, there have been no failures of buried components within the scope of license renewal in the service water, fuel oil, or fire water systems due to external surface degradation. This is primarily due to preventive measures to mitigate degradation (*e.g.*, external coatings and wrappings), and non-aggressive soil/ground water and lake water environmental conditions. The applicant stated that this is supported by the examples of plant-specific operating experience discussed in LRA Section B2.1.7. In addition, the applicant pointed to LRA Section 3.0.1.9, where it is stated that periodic chemical analyses of the soil/ground water and lake water will be performed to ensure that the below-grade environment remains chemically non-aggressive for the period of extended operation. The applicant concluded that a one-time inspection of various components within the scope of license renewal is not warranted prior to the period of operation. Inspections will be performed based on plant operating experience and opportunities for inspection. As additional operating experience is obtained, lessons learned may be used to adjust the basis of this program.

The staff found this response unacceptable since the fire protection piping was uncoated and previous excavations did not sufficiently document the condition of the fire protection piping. In its response to RAI B2.1.7-1, the applicant submitted a clarification letter, dated March 15, 2005, in which PBNP committed to schedule an inspection at a susceptible location in the fire protection system once, prior to entering the period of extended operation, and at least every 10 years during the period of extended operation; however, an inspection of opportunity on buried fire protection piping may be substituted for these scheduled inspections.

The staff found that the clarification response to RAI B2.1.7-1 addresses the staff's concerns described in RAI B2.1.7-3. These scheduled inspections are expected to ensure that buried components within the fire protection system are periodically monitored and inspected. Therefore, RAI B2.7.1-3 is resolved.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

FSAR Supplement. In LRA Section A15.2.7, the applicant provided the FSAR supplement for the Buried Services Monitoring Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review, RAI responses, and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with 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). The staff also reviewed the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.8 Cable Condition Monitoring Program

Summary of Technical Information in the Application. The applicant's Cable Condition Monitoring Program is described in LRA Section B2.1.8, "Cable Condition Monitoring Program." The applicant stated that this is a new program that is consistent, with enhancements, with GALL AMP XI.E1, "Electrical Cables And Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant further stated that the Cable Condition Monitoring Program is consistent, with exceptions and enhancements, with GALL AMP XI.E2, "Electrical Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits," and GALL AMP XI.E3, "Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."

The applicant stated that the Cable Condition Monitoring Program manages aging of conductor insulation materials on cables and connectors, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation, or moisture. The scope of this program includes accessible non-environmental qualification (non-EQ) electrical cables and connections, including control and instrumentation circuit cables, non-EQ electrical cables used in nuclear instrumentation circuits, and inaccessible non-EQ medium-voltage cables within the scope of license renewal.

The applicant also stated that the Cable Condition Monitoring Program provides reasonable assurance that the intended functions of electrical cables and connections within the scope of license renewal that are not subject to the environmental qualification requirements of 10 CFR 50.49 and are exposed to adverse localized environments caused by heat, radiation, or moisture are maintained consistent with the CLB through the period of extended operation. This program considers the technical information and guidance provided in NUREG/CR-5643," Insights Gained From Aging Research," IEEE Standard P1205-2000, "IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations," SAND-96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations," and EPRI TR-109619, "Guideline for the Management of Adverse Localized Equipment Environments."

This program addresses cables and connections whose configuration is such that most cables and connections installed in adverse localized environments are accessible. It is a sampling program where selected cables and connections from accessible areas are inspected and represent, with reasonable assurance, all cables and connections in adverse localized environments.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In LRA Section B2.1.8, the applicant stated that its Cable Condition Monitoring Program is consistent with GALL AMP XI.E1. The applicant further stated that its Cable Condition Monitoring Program is consistent, with exceptions, to GALL AMP XI.E2 and AMP XI.E3.

The Cable Condition Monitoring Program takes exception to the "scope of the program" program element for GALL AMP XI.E2 in that only non-EQ electrical cables used in nuclear instrumentation (NI) circuits that are within the scope of license renewal and are installed in adverse localized environments will be tested. This means that not all non-EQ instrumentation cable is tested for reduced insulation resistance (IR) value. GALL AMP XI.E2 states that this program applies to electrical cables used in circuits with sensitive, low-level signal such as radiation monitoring and nuclear instrumentation that are within the scope of license renewal.

The staff verified that all electrical cables associated with radiation monitoring and EQ nuclear instrumentation within the scope of license renewal are either environmentally qualified in accordance with 10 CFR 50.49 or not installed in adverse localized environments. In either circumstance, the deterioration of IR values are either maintained (by virtue of the EQ program) or do not exist (benign environment). On the basis of its review, the staff found this exception to be acceptable.

The Cable Condition Monitoring Program also takes exception to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements for GALL AMP XI.E2 in that the surveillance tests required by the PBNP technical specifications do not include the electrical cables for certain nuclear instrumentation circuits. Therefore, the applicant stated that its Cable Condition Monitoring Program periodically tests nuclear instrumentation circuits to provide an indication of the cable insulation condition.

For the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements associated with the exception taken by the applicant, the GALL AMP XI.E2 states, first, the parameters monitored are determined from the plant technical specifications and are specific to the instrumentation loop being calibrated, as documented in the surveillance test procedure; second, calibration provides sufficient indication of the need for corrective actions by monitoring key parameters and providing trending data based on acceptance criteria related to instrumentation loop performance; and third, calibration readings are to be within the loop-specific acceptance criteria, as set out in the plant technical specifications surveillance test procedures. The first test for license renewal are to be completed prior to entering the period of extended operation.

The staff reviewed the applicant's Cable Condition Monitoring Program and verified that the plant program, as documented in the staff's audit and review report, for the IR testing of non-EQ nuclear instrumentation is comprehensive and conservative in that it tests all non-EQ nuclear instrumentation circuits for insulation condition with the frequency required in the GALL Report. On the basis of its review, the staff found this exception acceptable.

The staff's review of LRA Section B2.1.8 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 RAIs as discussed below.

<u>RAI B2.1.8-1</u>. The Cable Condition Monitoring Program takes exception to the "scope of the program" program element for GALL AMP XI.E3 in that the Cable Condition Monitoring Program is based on prolonged exposure to significant moisture, which is defined as exposures to significant moisture that last more than a few years.

GALL AMP XI.E3 states that "significant moisture" is defined as "periodic exposures to moisture that last more than a few days (*e.g.*, cable in standing water)." In RAI B2.1.8-1, dated December 21, 2004, the staff requested the applicant to clarify the basis for this exception. In its response, a clarification letter dated March 15, 2005, the applicant deleted this specific exception related to significant moisture and agreed to perform the cable testing, with remaining exceptions, as described in the GALL AMP XI.E3. On the basis of its review and the RAI response, the staff found this acceptable. The staff's concern described in RAI B2.1.8-1 is resolved.

The Cable Condition Monitoring Program also takes exception to the "parameters monitored or inspected" and "detection of aging effects" program elements for GALL AMP XI.E3 in that the Cable Condition Monitoring Program requires periodic testing of a representative sample of in-scope, inaccessible medium-voltage cables not designed for submergence subject to prolonged exposure to significant moisture and significant voltage. Specifically, the testing is performed on a representative sampling of cable rather than on all cables.

RAI 3.6.2.1-7. In RAI 3.6.2.1-7, dated November 18, 2004, the staff requested the applicant to explain why testing of inaccessible medium-voltage cables for detecting deterioration of insulation due to moisture and voltage fluctuation is not needed. The staff requested the applicant to consider all inaccessible non-EQ electrical medium-voltage cables for testing.

In its response, dated January 25, 2005, the applicant stated:

> PBNP has tested all in-scope inaccessible Non-EQ medium-voltage cables. This testing was performed in 2003 and 2004 and no significant deterioration of the cables was found. On a ten-year testing interval, the next test will occur just after the end of the current license for Unit 1, but prior to the start of the period of the extended license for PBNP Unit 2. This will yield one additional test period versus if PBNP had waited until just prior to the end of the current licensed period for Unit 1 to perform the initial testing. PBNP intends to perform additional testing prior to the next scheduled ten-year test, as deemed prudent by our system engineering personnel, to ensure continued awareness of the condition of the aged medium-voltage cables.
>
> Since the program has not yet been developed, selection of the sample of medium-voltage cables to be tested is yet to be determined, but the cable sample selection for testing will be based on the severity of prolonged exposure to significant moisture and significant voltage, and the age of the cable. For example, for cables of the same size, construction, voltage and ampere loading, and age run in parallel conduit in the same underground duct bank, the sample may consist of only those cables in the lowest conduits, since they are more likely to be exposed to water.

GALL AMP XI.E3 states that in-scope, medium-voltage cables exposed to significant moisture and significant voltage are tested to provide an indication of the condition of the conductor insulation.

In response to RAI B2.1.8-1, the applicant also agreed to consider for testing all inaccessible non-EQ medium-voltage cables within the scope of license renewal not designed for submergence that are subject to significant moisture and significant voltage. A representative sample of in-scope, inaccessible, non-EQ, medium-voltage cables not designed for submergence subject to significant moisture and significant voltage will be tested prior to entering the period of extended operation and once every ten years thereafter. This sample will include those cables considered to be most susceptible and will represent all cable types and manufacturers. The basis for this representative sample will be documented. In addition, the applicant revised the definition of significant moisture to be consistent with that contained in the GALL AMP XI.E3. On the basis of its review and the discussion above, the staff found this acceptable. The staff's concern described in RAI 3.6.2.1-7 is resolved.

In LRA Section B2.1.8, the applicant stated that its Cable Condition Monitoring Program is consistent with GALL AMPs XI.E1, XI.E2,and XI.E3 with enhancements. The applicant stated that, for the "scope of the program" program element, enhancements to the Cable Condition Monitoring Program include establishing a new program that manages aging of conductor insulation materials on cables and connections, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation, or moisture. The staff considered this type of enhancement to be an administrative enhancement that does not require staff review.

Operating Experience. The staff reviewed the applicant's operating experience for the Cable Condition Monitoring Program.

In the LRA, the applicant stated the following:

> Industry operating experience has shown that adverse localized environments caused by heat or radiation for electrical cables and connections may exist next to or above (within three feet of) steam generators, pressurizers or hot process pipes, such as feedwater lines. These adverse localized environments have been found to cause degradation of the insulating materials on electrical cables and connections that is visually observable, such as color changes or surface cracking. These visual indications can be used as indicators of degradation.
>
> Industry operating experience has also shown that visual inspections of non-EQ instrumentation circuit cables within the scope of license renewal are adequate to identify aging degradation, as documented in SAND-96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants – Electrical Cable and Terminations." Exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced insulation resistance. Reduced insulation resistance can cause an increase in leakage currents between conductors and from individual conductors to ground. A significant reduction of insulation resistance is a concern for circuits with sensitive, high voltage, low-level signals such as radiation monitoring and nuclear instrumentation since it may contribute to inaccuracies in the instrument circuits.
>
> ... Plant-specific operating experience has shown that adverse localized environments caused by heat and moisture exist at PBNP. For example, the 4K VAC feeds to the Steam Generator Feed Pumps and from X04 have been exposed to adverse localized environments caused by heat and moisture, respectively. Maintenance work orders were generated to test and/or replace cables and connections that showed signs of aging due to adverse localized environments, as required.

Electrical cables associated with radiation monitoring instrumentation within the scope of license renewal at PBNP are either environmentally qualified in accordance with 10 CFR 50.49 or not installed in adverse localized environments (*e.g.*, radiation monitoring instrumentation associated with the control room). Non-EQ electrical cables used in nuclear instrumentation circuits within the scope of license renewal are included within the scope of the Cable Condition Monitoring Program. Operating experience has shown that anomalies found during cable testing can be caused by the degradation of the nuclear instrumentation circuit cable and are a possible indication of potential cable degradation.

Plant-specific operating experience has shown that changes to nuclear instrumentation cable are gradual and minimal over a long period of time. PBNP Unit 1 has operated for 33 years, and Unit 2 has operated for 31 years without any direct failure in the nuclear instrumentation cabling. Rather, particular cables have exhibited varying degrees of noise, decreased IR, and, in one case, a conductor-to-shield short. These conditions have decreased the signal quality but not interrupted or impaired the accuracy of the indication. In some cases of noise and reduced IR, this condition has been tracked over several years and little additional degradation has been observed. In the case of the conductor-to shield short, the cable was abandoned and a spare cable connected to reestablish the circuit.

... An NRC Inspection Report identified a finding regarding inadequate and untimely corrective actions relating to flooding of manholes containing safety and nonsafety-related cables. The inspectors reviewed corrective actions associated with flooded manholes containing electrical cables. Since 1997, numerous corrective action program documents have been written relating to flooded manholes, submerged cables in manholes, ice formation due to flooded manholes, effects of water on cables, and spurious alarms relating to manholes. Based on the number of corrective action program documents and associated ineffective corrective actions, the inspectors concluded that the applicant had not implemented effective corrective actions to address the problem of cables flooded in manholes.

A condition evaluation was performed as a result of questions raised during the inspection. In order to better understand the magnitude of the groundwater intrusion problem into the electrical manholes, a new call-up to inspect and pump the flooded manholes was initiated. The new call-up periodically inspects and pumps down the electrical manholes, as necessary. As part of the new call-up, the approximate water level in each manhole is recorded. The recording of the water level will provide the basis for any future changes in frequency to the call-up and any deletions of manhole inspections. Based on the corrective actions taken to evaluate pumping out the manholes throughout the year and to evaluate the need to inspect other manholes for similar conditions, the NRC finding was closed. A solution to prevent manhole and cable vault flooding is currently being pursued.

An NRC Inspection Report also identified an Unresolved Item concerning the effects of prolonged water submergence on 13.8K VAC, 4160 VAC, and 480 VAC electrical cables. The NRC determined that this issue did not represent an immediate safety concern. However, it was concerned that if the condition were left uncorrected it would become a more significant safety concern in subsequent years if cable degradation were to interrupt the continuity of offsite power to the safeguards electrical buses. In response to these concerns, a number of these cables, including all of the 13.8K VAC cables subject to submergence, were successfully tested in 2003 using the Energized Partial Discharge Testing Methodology. These cables will also be tested in the future in accordance with the test vendor's recommendations using a proven testing methodology. In addition, actions have been taken to prevent further cable submergence. Based upon these actions, the NRC closed this URI during the third quarter 2003.

As documented in the audit and review report, the above statements were reviewed during discussions with the applicant regarding the manhole flooding program. The staff reviewed the documentation for the applicant's electrical manhole inspection program. Records from the Computerized History and Maintenance Planning System (CHAMPS) were reviewed, showing the frequency of maintenance actions and conditions found in manholes. CHAMPS is a computer-based program in which records of work performed on plant SSCs are initiated and managed. For the data sets reviewed (previous 12 months), water level in the manholes did not reach the cable junctions. New manhole inspection and pumpdown procedures require that the as-found water level be recorded on the work request form. When entered into CHAMPS, these data will be trended and used to modify the inspection frequency as required to keep the water level below the cable connections.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience.

On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Cable Condition Monitoring Program, with exceptions as discussed, will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.8, the applicant provided the FSAR supplement for the Cable Condition Monitoring Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review, the RAI responses discussed above, and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.9 Closed-Cycle Cooling Water System Surveillance Program

Summary of Technical Information in the Application. The applicant's Closed-Cycle Cooling Water System Surveillance Program is described in LRA Section B2.1.9, "Closed-Cycle Cooling Water System Surveillance Program." The applicant stated that this is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.M21, "Closed-Cycle Cooling Water System."

The applicant stated that the Closed-Cycle Cooling Water System Surveillance Program manages aging effects in closed-cycle cooling water (CCCW) systems that are not subject to significant sources of contamination, in which water chemistry is controlled and heat is not directly rejected to the ultimate heat sink. The program includes (1) maintenance of system corrosion inhibitor concentrations to minimize degradation and (2) periodic or one-time surveillance testing and inspections to evaluate system and component performance. Inspection methods may include visual testing, ultrasonic testing (UT), and eddy current testing (ECT).

The program is applicable to the component cooling (CC) water system, the emergency diesel generator (EDG) coolant subsystems, gas turbine, gas turbine-associated diesel cooling subsystems, and the chilled water subsystems for the control room, computer room, and cable spreading room.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In LRA Section B2.1.9, the applicant stated that its Closed-Cycle Cooling Water System Surveillance Program is consistent with GALL AMP XI.M21, with exceptions. The Closed-Cycle Cooling Water System Surveillance Program takes exception to the "preventive actions" and "acceptance criteria" program elements such that the EDG and gas turbine-related cooling subsystems, and the ventilation chilled water subsystems corrosion inhibitor concentrations are maintained in accordance with the manufacturer's recommendation, not EPRI TR-107396, "Closed-Cooling Water Chemistry Guidelines."

GALL Report AMP XI.M21 states, for the "preventive actions" and "acceptance criteria" program elements, that the program should rely on the use of appropriate materials, lining, or coating to protect the underlying metal surfaces and maintenance of system corrosion inhibitor concentrations within specified limits of EPRI TR-107396 to minimize corrosion. The program includes monitoring and control of cooling water chemistry to minimize exposure to aggressive environments and application of corrosion inhibitor in the component cooling water system to mitigate general, crevice, and pitting corrosion.

The applicant stated that the EDG and gas turbine-related cooling subsystems, and the ventilation chilled water subsystems corrosion inhibitor concentrations are maintained in accordance with the manufacturer's recommendation, not EPRI TR 107396. The staff reviewed the EPRI guidance document and the PBNP operating experience. The staff observed that PBNP relies on the use of appropriate materials and a water treatment program to inhibit corrosion. In addition, potassium dichromate is used as the corrosion inhibitor in the CC system, and the chromate concentration limits fall within the typical control range provided in EPRI TR-107396 Table 4.2. The program includes the monitoring and control of CC system chemistry in order to minimize exposure to aggressive environments and to mitigate corrosion. The EDG, gas turbine, gas turbine-associated diesels cooling subsystems, and ventilation chilled water subsystems use commercial corrosion inhibitors. EPRI TR-107396 discusses these in general terms but does not provide specific concentration limits for the two products in use. The applicant maintains the corrosion inhibitor concentrations within the product manufacturer's recommended limits. The operating history indicates a lack of component degradation exposed to the CCCW system coolant.

On the basis of its review, the staff found that the support of the manufacturer's recommendations for chemistry concentrations is expected to maintain appropriate system operation. On this basis, the staff found this exception acceptable.

The Closed-Cycle Cooling Water System Surveillance Program also takes exception to the "parameters monitored or inspected" program element in that (1) PBNP does not reference EPRI TR-107396 in any of the CC system, EDG, gas turbine, or chilled water subsystem procedures, and as such does not monitor the CC system for corrosion products, calcium and magnesium, or refrigerant chemicals, (2) the parameters stated in GALL AMP XI.M21 are not monitored for all heat exchangers, only for a selected few in the CC system, (3) not all of the EPRI chemistry parameters are monitored for the EDG, gas turbine, gas turbine associated diesels coolant subsystems, and the ventilation chilled water subsystems, and (4) pump suction or discharge pressure and coolant flows are not monitored for the EDG, gas turbine and ventilation related subsystems.

GALL AMP XI.M21 states, for the "parameters monitored or inspected" program element, that this program should monitor the effects of corrosion by surveillance testing and inspections in accordance with standards in EPRI TR-107396 to evaluate system and component performance. For pumps, the parameters monitored include flow and discharge and suction pressures. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure.

For the first exception, the applicant stated that it did not reference EPRI TR-107396 in any of the CC system, EDG, gas turbine, or chilled water subsystem procedures. The EPRI document states that the system impurities that could be monitored are chlorides, fluorides, sulfates, corrosion products, calcium, and magnesium, refrigerant chemicals and radionuclides. The applicant stated that the Closed-Cycle Cooling Water System Surveillance Program periodically monitors CC system chemistry to verify it is being maintained within specified limits (pH, chloride, fluoride, chromate and sulfate concentrations, conductivity, and radioactivity).

The staff reviewed the information provided in the LRA. The staff found that it is not mandatory that the EPRI document be referenced, but that the important feature is what is monitored (*i.e.*, system chemistry). With these monitored parameters and operability tests performed on various system components, the staff found that the applicant has demonstrated satisfactory performance with the affected SSCs. On the basis of the consideration of the parameters monitored, the successful system operating history and operability test performance, the staff found the exception is acceptable.

For the second exception, the applicant stated that the parameters are not monitored for all heat exchangers, only for a selected few in the CC system. The applicant stated that the CC system flows are monitored, as are pump suction and discharge pressure. Selected heat exchangers are monitored for flow. Selected heat exchangers also are heat balance tested. The smaller heat exchangers, such as the seal water heat exchangers on the containment spray pumps, residual heat removal pumps, and the safety injection pumps and the sample system heat exchangers, do not have the capability of performing a heat balance test. Flows through these heat exchangers are set within specified ranges so that they are capable of performing their intended function. Periodic performance of system pressure testing of the component cooling system verifies that the pressure boundary function of the components in the component cooling system is maintained. This test is used to identify leaks and correct them prior to a loss of system or component intended function.

The staff reviewed the information provided in the LRA. The staff found that flow monitoring and pressure testing are sufficient to ensure that intended function is maintained. On the basis of its review, the staff found this exception acceptable.

For the third exception, the applicant stated that not all of the EPRI chemistry parameters are monitored for the coolant subsystems in the EDG, gas turbine, gas turbine associated diesels, and the ventilation chilled water. The applicant stated that the EDG coolant subsystems are periodically sampled and analyzed to maintain the corrosion inhibitor concentration within the manufacturer's recommended range. The ventilation chilled water system performance is periodically monitored by checking system pressures and temperatures. The coolant in diesel generators G01 and G02 is also checked for pH, microbiological contamination, conductivity, total suspended solids, iron, copper, calcium, and magnesium. Engine coolant temperatures are recorded during the monthly surveillance tests.

The staff reviewed the information provided in the LRA. On the basis of its review, the staff found that the sampling and surveillances of the coolant and controlled engine temperature provides a reasonable basis for successful operation of the subsystems. On this basis, the staff found this exception acceptable.

For the fourth exception, the applicant stated that it does not monitor pump suction or discharge pressure and coolant flows for the EDG, gas turbine and ventilation related subsystems. Operating experience confirmed acceptable performance of this equipment. The applicant stated that system performance assessments will continue to provide an indicator that a subsystem may be degraded and result in appropriate corrective actions.

The staff reviewed the information provided in the LRA. The staff found that the plant operating experience and system flow assessment is expected to ensure pump performance. On the basis of its review, and on the system limits, tests performed and the acceptable operating experienced observed, the staff found this exception acceptable.

The staff reviewed the applicant's Closed-Cycle Cooling Water System Surveillance Program, as documented in its audit and review report. The staff concluded that the applicant monitors the water chemistry and operating characteristics of the CCCW system in such a way that it enables the applicant to continue to confirm the effectiveness of the CCCW system.

The Closed-Cycle Cooling Water System Surveillance Program also takes exception to the "detection of aging effects" program element such that PBNP does not perform microbiological testing on the CC system, ventilation chilled water subsystems, or the coolant subsystems for the B train EDG, or the coolant systems associated with the gas turbine.

GALL AMP XI.M21 states that controlling water chemistry does not preclude corrosion at locations of stagnant flow conditions or crevices. Degradation of a component due to corrosion would result in degradation of system or component performance. The extent and schedule of inspections and testing in accordance with EPRI TR-107396 ensures detection of corrosion before the loss of intended function of the component. Performance and functional testing in accordance with EPRI TR-107396 ensures acceptable functioning of the CCCW system or components serviced by the system. For systems and components in continuous operation, performance adequacy is determined by monitoring data trends for evaluation of heat transfer fouling, pump wear characteristics, and branch flow changes. Components not in operation are periodically tested to ensure operability.

The applicant stated that it monitors CC water flows only through critical heat exchangers and monitors the overall system performance. EPRI TR-107396 also states that microbiological testing is performed on the bulk water in the CC system (planktonic organisms). The test can be performed to provide a good indication of trends in general microbiological control. Microbiological testing is performed on the nitrate based coolant used in G01 and G02 because this type of coolant is susceptible to microbiological contamination. The applicant does not perform this type of test on the CC system, ventilation chilled water subsystems, or the coolant subsystems for diesel generators G03 and G04, and the coolant systems associated with G05, G-500, and G-501. As previously stated, the chromates in the CC system are toxic to microbiological organisms, and plant experience has shown no problems with microbiological growth in the system. The glycol concentration in the ventilation chilled water subsystems, G03, G04, G05, G-500, and G-501 is maintained at a level where biological growth is inhibited. The applicant stated that these preventive actions preclude the need to perform microbiological testing.

Furthermore, the applicant stated that its One-Time Inspection Program is credited with the detection of corrosion in areas of stagnant flow conditions in the CC system. Periodic heat transfer testing of the CC heat exchangers provides indication of fouling. Various CC system operating parameters such as pressure, flow, and surge tank volume are monitored and will provide indications of system degradation. The EDGs, gas turbine, and gas turbine-associated diesels are not normally in operation but are periodically tested to ensure operability. Internal inspections of portions of the engines coolant subsystem will be performed via the One-Time Inspection Program. The ventilation chilled water subsystems are normally in operation, and system performance is periodically checked.

As documented in the audit and review report, the staff reviewed the information provided in the LRA and held technical discussions with the applicant. The staff concluded that the measures the applicant takes to monitor system chemistry and operating performance enable the applicant to continue to confirm the effectiveness of the CCCW system. The staff found that the applicant's One-Time Inspection Program supports the performance of its Closed-Cycle Cooling Water Surveillance Program, and will adequately sample those areas subject to low or stagnant flow as recommended by GALL AMP XI.M21. On this basis, the staff found this exception acceptable.

The Closed-Cycle Cooling Water System Surveillance Program also takes exception to the "monitoring and trending" program element in that (1) PBNP will perform tests as a result of CC system performance evaluations by the responsible engineer and (2) PBNP does not routinely perform heat removal capability tests on the EDG, gas turbine related coolant subsystems, and the ventilation chilled water subsystems.

GALL AMP XI.M21 states that the frequency of sampling water chemistry varies and can occur on a continuous, daily, weekly, or as-needed basis, as indicated by plant operating conditions. Pursuant to EPRI TR-107396, performance and functional tests are performed at least every 18 months to demonstrate system operability, and tests to evaluate heat removal capability of the system and degradation of system components are performed every five years. The testing intervals may be adjusted on the basis of the results of the reliability analysis, type of service, frequency of operation, or age of components and systems.

The applicant stated that the CC system water chemistry is sampled on a periodic basis and as indicated by plant operating conditions. Functional performance of the CC system is monitored with the in-place instrumentation. System pressure tests are performed per plant procedures. Thermal balance testing of the component cooling/service water heat exchangers is performed on a frequency in accordance with plant procedures. Plant procedures are used to set flows to heat exchangers or a group of heat exchangers, except for pump seal coolers. The EDG and gas turbine-related coolant subsystems are sampled on a periodic basis. The staff considers the in-place monitoring equipment as an acceptable alternative for performing periodic functional tests. Based on review of the associated EPRI documents, plant chemistry sampling, monitoring, and surveillance procedures, system performance tests, plant operating procedures, and operating history, and the applicant's response to questions, the staff found the measures the applicant takes to monitor system chemistry and operating performance enable the applicant to continue to confirm the effectiveness of the Closed-Cycle Cooling Water System Surveillance Program. On this basis, the staff found this exception acceptable.

The applicant does not routinely perform heat removal capability tests on the EDG and gas turbine-related coolant subsystems. However, operability testing is periodically conducted. These tests provide an indication of the heat flow performance of the EDG and gas turbine-related coolant subsystems. Based on the operability tests, and successful operation, the staff found this exception acceptable.

The applicant also does not routinely perform heat removal capability tests on the ventilation chilled water subsystems. These systems are normally in continuous operation, and system operating parameters are periodically checked to assess system performance. The continuous operation is an indication that the ventilation chilled water subsystems heat exchangers are performing appropriately. Based on the continuous operation and past successful operation, the staff found this exception acceptable.

In LRA Section B2.1.9, the applicant stated that its Closed-Cycle Cooling Water System Surveillance Program is consistent with GALL AMP XI.M21, with enhancements. The applicant stated that, for the "detection of aging effects" program element, enhancements to plant documents include revisions to ensure consideration of the applicable aging effects and to establish sampling periodicity and criteria for the coolant associated with the gas turbine and related diesel engines, and applicable ventilation chilled water subsystems. This is being done to ensure the appropriate concentration of corrosion inhibitor is being maintained in the coolant.

Enhancements also include (1) a review of the acceptable chloride and fluoride levels in the CC system, (2) the creation of procedural requirements for operating the system within the established acceptance ranges for the applicable chemical parameters, and (3) the completion of a strategy for a long-term condition assessment of the CC heat exchangers because of suspected galvanic corrosion of the tube support plates. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

<u>Operating Experience</u>. The staff reviewed the applicant's operating experience for the Closed-Cycle Cooling Water System Surveillance Program.

In the LRA, the applicant stated the following:

> Plant-specific operating experience indicates that CC system performance has been very good. The applicant has not experienced degradation of its CC system due to corrosion product build up or cracking. The chromate water treatment in the CC system has performed satisfactorily in mitigating loss of material and loss of heat transfer. Routine checks performed on the CC system by operators, such as monitoring flows through heat exchangers, monitoring system pressures at various locations, monitoring pump suction and discharge pressure, and monitoring temperatures of both the CC system and the components that the CC water is cooling, ensure early detection of CC system problems that will lead to corrective actions. The performance of a system pressure test is used to detect and eliminate unacceptable leaks.
>
> Tube vibration in the CC heat exchangers has been documented in the corrective action program. The vibration has been attributed to increased clearances in the tube-to-tube support plate interface. The CC heat exchangers were re-tubed with SeaCure tube material, which creates the potential for galvanic corrosion of the carbon steel tube support plates. Galvanic corrosion of the tube support plates is believed to be the reason for the increased clearances and subsequent tube vibration at high CC flows. A long-term condition assessment strategy for the CC heat exchangers is being developed regarding this issue.
>
> Trending of nitrite and microbiological levels in the engine coolant of G01 and G02 EDGs has revealed slight in-leakage of service water into the engine coolant. This resulted in the heat exchangers being inspected and repaired or replaced. Periodic nitrate depletion in G02 is an open issue that is being addressed via the corrective action process. There have been no significant degradation problems with the coolant subsystems of EDG G03 and G04, the gas turbine and associated equipment, and the ventilation chilled water subsystems. The Closed-Cycle Cooling Water System Surveillance Program provides reasonable assurance that these subsystems and components will continue to perform their intended functions.
>
> A review of NRC Inspection Reports, QA Audit/Surveillance Reports, and Self-Assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Closed-Cycle Cooling Water System Surveillance Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

The staff reviewed plant operating experience provided in the LRA and the plant method for data collection, as documented in the audit and review, and held discussion with the applicant's technical staff. On the basis of its review, the staff concluded that the Closed-Cycle Cooling Water System Surveillance Program, with identified exceptions, will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.9, the applicant provided the FSAR supplement for the Closed-Cycle Cooling Water System Surveillance Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions previously discussed, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.10 Fire Protection Program

Summary of Technical Information in the Application. The applicant's Fire Protection Program is described in LRA Section B2.1.10, "Fire Protection Program." The applicant stated that this is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.M26, "Fire Protection," and GALL AMP XI.M27, "Fire Water System," as clarified by Interim Staff Guidance (ISG)-04, "Aging Management of Fire Protection Systems for License Renewal."

The applicant stated that the Fire Protection Program consists of fire barrier inspections, electric and diesel-driven fire pump tests, halon fire suppression system inspections and tests, and water-based fire protection system inspections and tests. The fire barrier inspection requires periodic visual inspection of fire barrier penetration seals, fire dampers, fire barrier walls, ceilings and floors, and periodic visual inspections and functional tests of fire-rated doors to ensure that their functionality and operability are maintained. The electric and diesel-driven fire pumps are tested to ensure that an adequate flow of firewater is supplied and that there is no degradation of diesel fuel supply lines. The water-based fire protection systems are inspected and tested to provide reasonable assurance that fire water systems are capable of performing their intended function. Also, the applicant stated that its fire protection system credits the Buried Services Monitoring Program for the management of aging effects on the external surfaces of buried fire water system piping.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

The Fire Protection Program takes exception to the "preventive actions" program element for GALL AMP XI.M26 in that the fire protection evaluation report does not manage or prevent aging effects of components associated with fire prevention, fire detection, fire suppression, fire containment or alternative shutdown capability. Therefore, the fire protection evaluation report is not addressed in the fire protection AMP. GALL AMP XI.M26, as modified by ISG-04, states that a fire hazard analysis is to assess the fire potential and fire hazard in all plant areas, and to specify measures for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability for each fire area containing SSCs important to safety.

The staff verified that the fire protection evaluation report assessed the fire potential and fire hazard in all plant areas, and specified measures for fire prevention, detection, suppression, and containment, as well as alternative shutdown capability for each fire area containing SSCs important to safety, as the fire hazard analysis, named in the GALL Report, specifies. Therefore, the staff determined that the generic GALL Report term "fire hazard analysis" equates to the PBNP-specific term "fire protection evaluation report," because each performs the same actions and specifies the same measures. With regard to the exception, noted above, the staff did not expect to find requirements to manage or to prevent aging effects in the requirements in the fire protection evaluation report. The purpose of this fire protection evaluation report is not to manage or to prevent aging effects, but to demonstrate that the plant will maintain the ability to perform safe shutdown functions and to minimize radioactive material releases to the environment in the event of a fire. The staff did find requirements to manage and to prevent aging in this fire protection AMP. It is this AMP, with its specific program elements, that actually manages or prevents aging effects on the specified components associated with the above systems. The staff learned that the applicant had identified this as an exception on the basis that the program element contained requirements that did not manage or prevent aging effects. The applicant had complied with the GALL Report specification but wanted to call attention to the fact that the requirements did not actually manage or prevent aging effects. On the basis of its review, and for the reasons discussed herein, the staff found this exception acceptable.

The Fire Protection Program takes exception to the parameters monitored and inspected, the detection of aging effects, and the "monitoring and trending program" elements for GALL AMP XI.M26 in that the visual inspection of fire barrier penetration seals is performed on a 4.5-year inspection frequency, with approximately one-third of these seals being inspected every 18-months. The applicant stated that the inspection frequency of the visual inspections of the fire barrier penetration seals, during which approximately 33 percent of the total seal population are inspected, meets and exceeds that inspection frequency that is recommended by the GALL Report, as modified by ISG-04. GALL AMP XI.M26, as modified by ISG-04, states that visual inspection of 10 percent of each type of penetration seal is to be performed at least once during every refueling outage.

The staff verified that the inspection frequency of the visual inspections of the fire barrier penetration seals, at approximately 33 percent versus 10 percent, exceeds the inspection frequency that is recommended by the GALL Report, as modified by ISG-04. As such, the staff found this exception acceptable.

The Fire Protection Program takes exception to the "detection of aging effects" program element for GALL AMP XI.M26 in that PBNP inspection personnel are not qualified to perform VT-1 or VT-3 visual inspections. GALL AMP XI.M26, as modified by ISG-04, states that VT-1 or equivalent and VT-3 or equivalent visual inspections are to be performed and, therefore, allows alternative inspections to be performed.

The staff reviewed the information provided by the applicant, as documented in the audit and review report. The staff verified that, although the inspection personnel were qualified to perform these inspections in accordance with PBNP procedures, they were not qualified in accordance with VT-1 or VT-3. The staff determined that the applicable inspection procedures contained procedure requirements and acceptance criteria that were of sufficient detail and conservatism that they were the equivalent to those recommended for VT-1 and VT-3 visual inspection. The staff noted the practical matter that those personnel who install the fire barrier components, (*i.e.*, those who were the most familiar with them), were the principal inspectors who performed the required visual inspections. The staff also noted the further conservative measure that these inspectors reported any discrepancy discovered during the inspection to the fire protection system engineer or the fire protection engineer for his evaluation and disposition under the applicant's corrective action program. Therefore, the staff concluded that the detail and conservatism provided in the inspection procedures were sufficient to assure that an inspection equivalent to VT-1 or VT-3 will be performed. On the basis of its review and the above discussion, the staff found this exception acceptable.

The Fire Protection Program takes exception to the "detection of aging effects" program element for GALL AMP XI.M27 in that PBNP performs monthly yard fire hydrant inspections and annual yard fire hydrant flushing, which is not in accordance with NFPA 25. The Fire Protection Program also takes exception to the "detection of aging effects" program element for GALL AMP XI.M27 in that PBNP checks the flow capacity of the main fire loop annually, but does not measure individual fire hydrant flow. GALL AMP XI.M27, as modified by ISG-04, states that visual inspection of yard fire hydrants is to be performed annually, in accordance with NFPA 25, and that fire hydrant hose hydrostatic tests, gasket inspections, and fire hydrant flow tests are to be performed annually.

The staff noted that NFPA 25 recommends a fire hydrant visual inspection to be performed annually and after each operation, and determined that PBNP, in performing monthly fire hydrant visual inspections, exceeds this NFPA 25 recommendation. The staff noted that PBNP treats fire hydrant hoses and gaskets as consumables, and that these components are within the scope of license renewal. The staff further noted that hoses and gaskets are visually inspected monthly and the hoses are hydrostatically tested on a frequency of 18 or 36 months, depending on the hose location. In the event that the hose or gasket does not pass the visual inspection, or the hose does not pass the hydrostatic test, it is replaced. Therefore, the staff concluded that this practice precludes any aging concern for these components. The staff verified that main fire loop flow capacity test that PBNP performs annually, has a flow capacity that meets and exceeds that of any single fire hydrant. On the basis of its review and for the reasons discussed above, the staff found this exception acceptable.

The Fire Protection Program takes exception to the "monitoring and trending" program element for GALL AMP XI.M27 in that inspection and testing is performed in accordance with the nuclear insurance carrier's fire protection system testing requirements and generally follows the guidance of the applicable NFPA codes and standards. GALL AMP XI.M27, as modified by

ISG-04, states that system performance testing results are monitored and trended as specified by the NFPA codes and standards.

The staff reviewed the information provided by the applicant, as documented in its audit and review report. The staff found significant deviations between PBNP fire protection system testing requirements and NFPA codes and standards testing requirements. The staff determined that the applicable NFPA standard in effect at PBNP is NFPA 13, "Standard for the Installation of Sprinkler Systems." The applicant performed a code compliance review of NFPA 13 and developed a justification to demonstrate that the PBNP fire protection system testing requirements are changed such that an equivalent level of protection is achieved. The staff compared the monitoring and trending recommendations of NFPA 13 to those of the nuclear insurance carrier's fire protection system testing and determined that the PBNP monitoring and trending requirements exceed those of NFPA 13. On the basis of its review and for the reasons discussed above, the staff found this exception acceptable.

The Fire Protection Program takes exception to the "acceptance criteria" program element for GALL AMP XI.M27 in that PBNP does not specifically inspect for biofouling in its sprinkler systems. GALL AMP XI.M27, as modified by ISG-04, states that no biofouling that could cause corrosion in the sprinkler systems is to exist.

The staff determined that the applicant takes actions to minimize biofouling in fire system components. These actions include flushing, performance testing, inspections, and chlorination when circulation water temperature exceeds 45 °F. The staff verified that PBNP plans to inspect or replace sprinkler heads prior to exceeding their 50-year service life in accordance with NFPA 25. If the sprinkler head is not replaced, the required testing will be repeated at 10-year intervals. The inspection of the sprinkler heads will identify any corrosion, which will then be addressed in accordance with the PBNP corrective action program and, therefore, accomplish the goal that no biofouling that could cause corrosion will exist. Periodically, the sprinkler lines are partially flushed, and prior to replacement they will be drained, at which time, any loose corrosion products will be evident. The disposition of any corrosion products that are detected will be in accordance with the applicant's corrective action program. On the basis of its review and for the reasons discussed above, the staff found this exception acceptable.

In LRA Section B2.1.10, the applicant stated that its Fire Protection Program is consistent with GALL AMP XI.M26 and GALL AMP XI.M27, with enhancements. The applicant stated that, for the "scope of the program" and "detection of aging effects" program elements, enhancements include revisions to various existing implementing documents to add specific inspections, monitoring and trending requirements, and/or frequency adjustments based on operating experience. Additionally, new implementing documents will be created to cause inspections of selected components and portions of the fire suppression piping. An evaluation will be performed to determine which non-Appendix R safe shutdown fire dampers may need to be added to the program. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

Operating Experience. The staff reviewed the applicant's operating experience for the Fire Protection Program.

The applicant stated that plant-specific operating experience has shown that after thirty plus years of operation the fire protection system performed well. There have been some cases of small pipe threaded connection leaks, small pipe external corrosion leaks, spray nozzles for the transformer deluge system plugged due to rust scale build-up, and cracked piping and fittings. Pinhole leaks have also been found on the 10-inch fire water supply header and sprinkler heads have been found to leak. These discrepancies were discovered in the last 13 years and were repaired using maintenance work orders.

The applicant also stated that its Fire Protection Program has been an ongoing program at PBNP. The program has evolved over the years of plant operation and has been enhanced by the implementation of 10 CFR Part 50, Appendix R and 10 CFR 50.48. The overall effectiveness of the program is demonstrated by the operating experience of SSCs that are subject to the Fire Protection Program.

Furthermore, the applicant performed a review of NRC inspection reports, QA audit/surveillance reports, and self-assessments since 1999 performed to determine the overall effectiveness of the program. The results of this review indicated that the overall effectiveness of the Fire Protection Program was good.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. The staff found that the operating experience is consistent with industry practice. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Fire Protection Program, with the identified exceptions, will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.10, the applicant provided the FSAR supplement for the Fire Protection Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.11 Flow-Accelerated Corrosion Program

Summary of Technical Information in the Application. The applicant's flow-accelerated corrosion program is described in LRA Section B2.1.11, "Flow-Accelerated Corrosion Program." The applicant stated that this is an existing program. As modified by letters dated April 8 and June 9, 2005, the applicant stated that this program is consistent, with exceptions and enhancements, with GALL AMP XI.M17, "Flow-Accelerated Corrosion."

The applicant stated that the Flow-Accelerated Corrosion Program manages aging effects due to flow-accelerated corrosion (FAC) on the internal surfaces of carbon or low-alloy steel piping, elbows, reducers, expanders, and valve bodies that contain high energy fluids (both single-phase and two-phase). The applicant also stated that the program implements the EPRI guidelines in NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program," for an effective Flow-Accelerated Corrosion Program and includes (a) an analysis using a predictive code such as CHECWORKS to determine critical locations, (b) baseline inspections to determine the extent of thinning at these locations, (c) follow-up inspections to confirm the predictions, and (d) repairing or replacing components, as necessary.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report.

In LRA Section B2.1.11, the applicant stated that its Flow-Accelerated Corrosion Program is consistent with GALL AMP XI.17, with enhancements. The applicant stated that, for the "scope of the program" program element, it will enhance the Flow-Accelerated Corrosion Program to add SG feedwater nozzles and attached reducers to the scope of the Flow-Accelerated Corrosion Program.

GALL AMP XI.17 states that, for "scope of the program" program element, the Flow-Accelerated Corrosion Program, described by the EPRI guidelines in NSAC-202L-R2, includes procedures or administrative controls to assure that the structural integrity of all carbon steel lines containing high-energy fluids (two phase as well as single phase) is maintained.

The applicant stated that its SG AMR identified the need to include the SG feedwater nozzles and attached reducers to the Flow-Accelerated Corrosion Program.

As documented in the audit and review report, the staff reviewed the information provided by the applicant and held discussions with the applicant's technical staff. The staff concluded that this enhancement to the Flow-Accelerated Corrosion Program scope is acceptable and will ensure that wall thinning in Units 1 and 2 SG feedwater nozzles will be managed according to the guidelines in NSAC-202L-R2 and that appropriate administrative controls will be in place to ensure that the structural integrity is maintained in carbon steel, high-energy locations. On this basis, the staff found this enhancement acceptable.

The staff's review of LRA Section B2.1.11 identified an area 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.

RAI B2.1.11-1. During the audit, the staff noted that for the "acceptance criteria" program element, it is unclear how the applicant calculates the minimum permitted wall thickness and uses in its analysis for FAC. In RAI B2.1.11-1, dated March 30, 2005, the staff requested the applicant to clarify its wall thickness calculation and its uses.

The staff's concern was referred to the Region III staff, which performed its AMR/AMP onsite inspection during the weeks of March 7 and 21, 2005. The applicant clarified its methodology. The applicant stated that the minimum wall calculations are performed using the design pressure, which is greater than the operating pressure and demonstrates that the actual measured wall thickness is greater than the minimum thickness required by the maximum hoop stress. If degradation is detected such that the wall thickness is less than or equal to 87.5 percent of nominal wall thickness for safety-related piping or 60 percent for nonsafety-related piping, additional examinations will be performed in adjacent areas to bound the thinning. The applicant will provide its justification to confirm that the minimum wall thickness will be maintained for the period of extended operation. This was identified as confirmatory item (CI) B2.1.11-1.

In its response to CI B2.1.1-11, by letter dated June 9, 2005, the applicant stated that during the Region III AMR/AMP onsite inspection, a detailed review of the Flow-Accelerated Corrosion Program was completed. As a result of that review and discussions between the Region III staff, the License Renewal Branch, and Division of Engineering personnel, PBNP provided a clarification to LRA Section B2.1.1.11, "Flow-Accelerated Corrosion Program," by letter dated April 8, 2005. Based upon discussions with the NRC staff on May 3, 2005, a revision to the April 8, 2005, letter was identified as being needed to clarify the intent of the sample expansion criterion. By letter dated June 9, 2005, the applicant provided a modified text to clarify its program. The revised text replaced the discussion under the program element "Monitoring and Trending" in LRA Section B2.1.11, as follows:

> If degradation is detected such that the wall thickness is less than or equal to 87.5% of nominal wall thickness for safety-related piping, additional examinations will be performed in adjacent areas to bound the thinning. For both safety-related and non-safety related piping, additional examinations will be performed in adjacent areas to bound the thinning if the remaining service life, based on the code minimum allowable wall thickness, is less than one operating cycle. The sample size will also be expanded for non-safety related piping if degradation is detected such that the wall thickness is less than or equal to 60% of nominal wall thickness. This covers situations where the code minimum allowable wall thickness may be less than 60% of nominal wall thickness for non-safety related piping. The expansion of the sample size should include a minimum of the next two most susceptible components in that CHECWORKS line, any component within two pipe diameters downstream (upstream if expander), or like components in parallel trains. If the initial expansion finds additional components with significant loss of material due to FAC, the examination scope is expanded further.
>
> This element includes exceptions to the corresponding NUREG-1801 aging management program element. NUREG-1801 states: "If degradation is detected such that the wall thickness is less than the minimum predicted thickness, additional examinations are performed in adjacent areas to bound the thinning." Literal interpretation of this sample expansion criteria is not practical in many cases. If very little degradation is predicted, measured wall thickness may be less than the predicted thickness even though the calculated life of the affected component may exceed the operating life of the plant. In this case, sample expansion would not be warranted.
>
> The FAC program at PBNP implements the EPRI guidelines in NSAC-202L-R2, which recommends increasing the sample size when inspections of the sample detect significant FAC wear. In the PBNP FAC program, significant FAC wear is defined as FAC resulting in a wall thickness of less than or equal to 87.5% of nominal wall thickness for safety related piping. For both safety related and non-safety related piping, additional examinations will be performed in adjacent areas to bound the thinning

if the remaining service life, based on the code minimum allowable wall thickness, is less than one operating cycle. The sample size will also be expanded for non-safety related piping if degradation is detected such that the wall thickness is less than or equal to 60% of nominal wall thickness. This covers situations where the code minimum allowable wall thickness may be less than 60% of nominal wall thickness for non-safety related piping. This criterion for sample expansion is acceptable because it specifies a wall thickness criterion and requires projection of inspection results to the next inspection opportunity consistent with industry guidance. Therefore, PBNP meets the intent of this NUREG-1801 aging management program element.

The staff reviewed the applicant's responses to RAI B2.1.1-11, its exception to the GALL Report, and the final text to be included in the AMP, and concluded that the applicant appropriately defined the program and demonstrated that the program, as defined, provides reasonable assurance that structural integrity will be maintained. The staff's concern is resolved; therefore, CI B2.1.1-11 is closed.

The applicant also stated that for the "detection of aging effects" and "acceptance criteria" program elements, enhancements include revising procedures to ensure congruence with the guidelines of NSAC-202L-R2 and provide better references to the input data sets. Enhancements also include (1) clarification of the program requirements for SG nozzles and reducers and more stringent controls placed on program basis documentation and software, and (2) revise procedures to require a local thinning evaluation if the measured wall thickness is less than t-min. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

Operating Experience. The staff reviewed the applicant's operating experience for the Flow-Accelerated Corrosion Program.

The applicant stated that it performed a comprehensive review of industry issues and service and its relevance to PBNP, including wall-thinning problems in single-phase systems in feedwater and condensate systems, two-phase piping in extraction steam lines, and moisture separation reheater and feedwater heater drains. The applicant's plant-specific operating experience review refers to a single event involving a feedwater heater steam leak at Unit 1 in 1999 due to steam impingement and FAC. Subsequent to the failure, inspections were performed and repairs were made due to wall thinning. Unit 2 heater materials were FAC-resistant, and no wall thinning was noted.

The staff noted that, based on its review of the LRA discussion of this plant-specific event, it was not clear to the staff that the Flow-Accelerated Corrosion Program was effective in detecting wall thinning in the Unit 1 feedwater heater prior to failure. In addition, it appears that wall thinning in the other heaters was discovered and examined only after the first heater failed.

The applicant explained, during discussions between the staff and the applicant's technical staff, that the Flow-Accelerated Corrosion Program did not detect this condition, as feedwater heaters were not included within the scope of the program at the time. Immediately prior to this event, PBNP was evaluating industry operating experience (OE) on feedwater heater degradation. The timing of the industry OE did not allow for OE evaluation before the occurrence of the event. The Flow-Accelerated Corrosion Program was revised to include feedwater heaters within the scope of the program.

The applicant stated that the Flow-Accelerated Corrosion Program identified component thinning conditions that resulted in corrective actions being pursued prior to component failure. The applicant described two examples where thinning in the main feedwater pumps and heater drain tank pumps' mini recirculation lines was discovered, the inspection scope was expanded, and sections of the lines were replaced with more corrosion-resistant materials. The applicant stated that the most common enhancements to the program are associated with scope additions and program process improvements resulting from Flow-Accelerated Corrosion Program findings, industry operating experience, and internal assessment recommendations.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Flow-Accelerated Corrosion Program, with the identified enhancements, will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.11, the applicant provided the FSAR supplement for the Flow-Accelerated Corrosion Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.12 Fuel Oil Chemistry Control Program

Summary of Technical Information in the Application. The applicant's Fuel Oil Chemistry Control Program is described in LRA Section B2.1.12, "Fuel Oil Chemistry Control Program." The applicant stated that this is an existing program that is consistent, with exceptions and enhancement, with GALL AMP XI.M30, "Fuel Oil Chemistry Control Program."

The applicant stated that the Fuel Oil Chemistry Control Program mitigates and manages aging effects on the internal surfaces of fuel oil storage tanks and associated components in systems that contain fuel oil. The program includes (1) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM standards, (2) periodic draining of water from fuel oil tanks, (3) periodic or conditional visual inspection of internal surfaces or wall thickness measurements from external surfaces of fuel oil tanks, and (d) one-time inspections of a representative sample of components in systems that contain fuel oil.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In LRA Section B2.1.12, the applicant stated that its Fuel Oil Chemistry Control Program is consistent with GALL AMP XI.M30, with exceptions. The Fuel Oil Chemistry Control Program takes exception to the "preventive actions" program element for GALL AMP XI.M30 in that PBNP does not routinely add corrosion inhibitors, stabilizers, or biocides to the fuel oil. However, fuel oil additives would be considered if sample results indicate the presence of these degradation mechanisms.

GALL AMP XI.M30 states that the quality of fuel oil is maintained by additions of biocides to minimize biological activity, stabilizers to prevent biological breakdown of the diesel fuel, and corrosion inhibitors to mitigate corrosion. Periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. Coatings, if used, prevent or mitigate corrosion by protecting the internal surfaces of the tank from contact with water and microbiological organisms.

The applicant stated that its Fuel Oil Chemistry Control Program is geared to the discovery and correction of conditions that could lead to degradation of fuel oil system components. Accumulated water is periodically removed from the tanks. Draining of accumulated water will also remove sediments from the tanks. The quality of new fuel oil is verified and the quality of stored fuel oil is periodically checked. These actions will mitigate loss of material in the fuel oil tanks and other components.

As documented in the audit and review report, the applicant stated that if tank wall and bottom thickness are determined via UT measurements from outside the tank, there is no need to remove the tank (and associated equipment) from service and drain, clean, and inspect the inside of the tank. Periodic removal of free water and sediment via tank drain valves or via use of a bottom sample thief are expected to minimize conditions and environment conducive to tank corrosion.

Additionally, the applicant stated that the EDG below-ground tanks and underground tank are drained and inspected only if deemed necessary based on the results of the fuel oil sample analysis or as recommended by the system engineer. The staff found this to be acceptable based on the inspection results of above-ground tanks, which are considered to be in a more severe environment and have shown no appreciable material loss in more than 30 years of service. Additionally, wall thickness measurements of the underground tank indicate that no appreciable material loss has occurred in more than 30 years of service. Significant degradation of the inside surfaces of the EDG below-ground tanks and underground tank, or conditions expected to cause such degradation, would be evidenced by the quarterly particulate and stability oil sample analysis results and/or identified by routine inspections or tests performed on supported equipment, which is monitored by the system engineer. There are no expected aging effects for the outside surface of the EDG below-ground tanks because they are encased in concrete.

In addition, the applicant indicated that operating experience validates that there is no need for chemical addition to the fuel oil system; the applicant continues to monitor operations for indications of aging conditions to warrant chemical addition and will do so if deemed necessary. Therefore, the applicant stated that no chemical addition is the preferred method at this time.

As documented in the audit and review report, the staff reviewed the information provided by the applicant and held discussions with the applicant's technical staff. On the basis of its review and on plant-specific operating history, the test results and the results of contaminant monitoring which shows no indication of aging in the various tanks, the staff found this exception acceptable.

The applicant's Fuel Oil Chemistry Control Program also takes exception to the "parameters monitored or inspected" and "acceptance criteria" program elements for GALL AMP XI.M30 in that the applicant (1) uses only D 2709 to determine the amount of contamination due to water and sediment in diesel fuel, (2) uses D 6217 in lieu of D 2276 for particulate determination, (3) uses a filter with a pore size no larger than 0.8 micron, and (4) uses ASTM D 2274 for stability analysis.

GALL AMP XI.M30 states that the AMP should monitor fuel oil quality and the levels of water and microbiological organisms in the fuel oil, which cause the loss of material of the tank internal surfaces and are the principal parameters relevant to maintaining tank structural integrity. ASTM Standard D4057 is used for guidance on oil sampling. ASTM Standards D1796 and D2709 are used for determination of water and sediment contamination in diesel fuel. For determination of particulates, modified ASTM Standard D2276, Method A, is used.

The staff reviewed and compared the referenced ASTM Standards D1796, D2709, D6217, D2276, and D4057; and the information provided by the applicant, as documented in the audit and review report. On the basis of its review, the staff found that ASTM D2709 is a test method that addresses the determination of volume of free water and sediment in middle distillate fuels. This standard has been revised since the issuance of the GALL Report. It is no longer a "pass/fail" test but actually quantifies the amount of water and sediment measurable to 0.01 mL. The staff reviewed the results of the last quarterly inspection report and found that the test as run is sensitive enough to verify that the water/sediment content is less than the applicant's limit of 0.05 percent. D1796 provides another quantified method of analysis and is applicable to higher viscosities of oil. Interviews with plant staff indicate that corrective actions are taken if any water or particulate are found in the oil above the 0.05 percent limit. Because ASTM D2709 meets the inspection criteria, the staff found this approach acceptable.

The applicant stated that ASTM D2276 as recommended in GALL AMP XI.M30 is applicable to aviation fuel, whereas ASTM D6217 is applicable to middle distillate fuel used in diesel engines. Therefore, with regard to the use of ASTM D2276 versus D6217, the staff agreed and found the applicant's approach and basis for using Standard D6217 to be acceptable.

The applicant stated that it also uses a filter with a pore size no larger than 0.8 micron versus GALL AMP XI.M30 recommendation of 3.0 micron, therefore, PBNP is more conservative. On the basis that the applicant uses a more conservative filter, the staff found this acceptable.

The applicant also stated that it uses ASTM D 2274 for stability analysis. The level of microbiological organisms in the fuel oil is not directly measured but can be inferred from the particulate and stability parameters. Since the applicant does not routinely add biocides, it performs stability analysis to assess if biocides should be added. The staff reviewed the use of the ASTM standard and agreed that applicant use of ASTM standard for stability analysis is acceptable. On this basis, the staff found this exception acceptable.

The applicant's Fuel Oil Chemistry Control Program also takes exception to the "detection of aging effects" program element for GALL AMP XI.M30 in that PBNP does not periodically perform an internal inspection of all of the fuel oil tanks.

GALL AMP XI.M30 states that degradation of the diesel fuel oil tank cannot occur without exposure of the tank internal surfaces to contaminants in the fuel oil, such as water and microbiological organisms. Compliance with diesel fuel oil standards in the "parameters monitored or inspected" program element and periodic multilevel sampling provides assurance that fuel oil contaminants are below acceptable levels. Internal surfaces of tanks that are drained for cleaning are visually inspected to detect potential degradation. However, corrosion may occur at locations in which contaminants may accumulate, such as a tank bottom, and an ultrasonic thickness measurement of the tank bottom surface ensures that significant degradation is not occurring.

The applicant stated that day tanks for the diesel-driven fire pump and emergency diesel generators are examined externally via UT wall thickness measurements, which the GALL AMP XI.M30 program description describes as an acceptable verification program. Furthermore, the applicant stated that the emergency diesel generator below-ground storage tanks and the underground emergency fuel tank are drained and inspected only if deemed necessary based on the trends indicated by the results of the fuel oil analysis, or as recommended by the system engineer based on equipment operating experience. This is considered acceptable based on the inspection results of the underground emergency fuel tank and the above-ground storage tanks, which were inspected in 2000 and showed no appreciable material loss in over thirty years of operation. The emergency diesel generator below-ground storage tanks are relatively new tanks, which were installed in the 1994 time frame and are in a less severe environment than the above-ground storage tanks.

The staff reviewed the information provided by the applicant, as documented in the audit and report, and held technical discussion with the applicant's staff. On the basis of its review, the staff determined that the applicant's Fuel Oil Chemistry Control Program does not require periodic visual examinations and UT of all tanks. The program requires different measures for different tanks, and no tanks require both periodic visual inspection and UT as recommended by the GALL AMP XI.M30. On this basis, the staff found this exception acceptable.

In LRA Section B2.1.12, the applicant stated that its Fuel Oil Chemistry Control Program is consistent with GALL AMP XI.M30, with enhancements. The applicant stated that, for the "detection of aging effects" program element, enhancements include revision of existing implementing documents and/or creation of new implementing documents to (1) periodically drain water from the gas turbine starting and auxiliary diesel fuel tanks, (2) periodically drain and inspect the gas turbine starting and auxiliary diesel fuel tanks and the two above-ground storage tanks, and (3) periodically take UT thickness measurements of the EDG and diesel-driven fire pump day tanks. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

Operating Experience. The staff reviewed the applicant's operating experience for the Fuel Oil Chemistry Control Program.

The applicant stated that (1) the operating experience of some plants included identification of water in the fuel, particulate contamination, and biological fouling, (2) a search of plant-specific operating experience revealed past problems with sampling methods, which were corrected with a revision to the sampling procedure, (3) problems were noted also with the particulate levels of delivered fuel oil and were attributed to the fuel oil cloud point and cold weather, (4) QA audits of the laboratory that performs the analysis of the fuel oil samples indicate that the laboratory is performing satisfactorily, (5) the internals of the above-ground fuel oil tanks and the underground emergency fuel tank were inspected in August 2000 and no significant rust deposits, corrosion, or other obvious defects were found, (6) thickness measurements of the underground emergency fuel tank and the bottom of the above-ground fuel oil tanks were performed and indicated no significant loss of material, (7) there have been no identified instances of component failure due to loss of material resulting from fuel oil contamination, and (8) a review of NRC inspection reports, QA audit/surveillance reports, and self-assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Fuel Oil Chemistry Control Program.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. The staff found that the operating experience is consistent with industry practice. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Fuel Oil Chemistry Control Program, with the exceptions identified above, will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.12, the applicant provided the FSAR supplement for the Fuel Oil Chemistry Control Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.13 One-Time Inspection Program

Summary of Technical Information in the Application. The applicant's One-Time Inspection Program is described in LRA Section B2.1.13, "One-Time Inspection Program." The applicant stated that this is a new program that is consistent, with exceptions and enhancements, with

GALL AMP XI.M32, "One-Time Inspection Program," and GALL AMP XI.M33, "Selective Leaching of Materials."

The applicant stated that the One-Time Inspection Program addresses potentially long incubation periods for certain aging effects and provides a means of verifying that an aging effect is either not occurring or progressing so slowly as to have negligible effect on the intended function of the structure or component. Hence, the One-Time Inspection Program provides measures for verifying an AMP is not needed, verifying the effectiveness of an existing program, or determining that degradation is occurring that will require evaluation and corrective action.

The applicant further stated that the program elements include (1) determination of appropriate inspection sample size, (2) identification of inspection locations, (3) selection of examination technique, with acceptance criteria, and (4) evaluation of results to determine the need for additional inspections or other corrective actions. The inspection sample includes locations where the most severe aging effect(s) would be expected to occur. Inspection methods may include visual (or remote visual), surface or volumetric examinations, or other established NDE techniques.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In LRA Section B2.1.13, the applicant stated the following with respect to the methods used to monitor or inspect degradation of components under the One-Time Inspection Program:

> For verification of the effectiveness of the Water Chemistry Control Program and the Closed-Cycle Cooling Water System Surveillance Program for stagnant or low flow areas and for verification of the effectiveness of the Fuel Oil Chemistry Control Program, a visual examination or other appropriate NDE methodology will be used to verify that degradation due to the applicable aging effects is not occurring.

The staff found that the applicant did not describe parameters directly related to the degradation of a component as required by the GALL Report. The GALL Report states that a link should be established between the degradation of the particular structure or component intended function(s) and the parameter(s) being monitored.

During the audit, the staff requested the applicant to provide a description that clearly identifies the link(s) between the parameters monitored or inspected and the aging effect for the particular structure or component. The inspection method selected for the parameter to be monitored shall be capable of measuring the parameter. The method is to be able to provide data that are adequate to conclude that the aging effect is managed consistent with the CLB.

In its response, dated July 12, 2004, the applicant provided a table, included below, which will be added to the LRA during its annual update, which links the aging effects/mechanisms managed by the One-Time Inspection Program with the parameters monitored/inspected and the measurement methodology. The inspection method identified is capable of measuring the parameter monitored and providing data that are adequate to conclude the aging effect is managed consistent with the CLB. If an inspection method different from that listed in the table below is used, the basis for the revised inspection method will be documented. The One-Time Inspection Program manages these aging effects/mechanisms on the internal surfaces of components. Visual inspections are performed only when the components are drained/opened and the component surface of interest is accessible. If degradation is identified through a visual inspection, additional NDE may be performed to characterize the degradation and determine the extent of the condition.

Table 3.0.3.2-1 Relationship of Parameters Monitored or Inspected and Aging Effect

Aging Effect	Aging Mechanism	Parameter Monitored	Measurement Method
Loss of Material	Crevice Corrosion	Wall Thickness	Visual (VT-1) and/or Volumetric (RT or UT)
Loss of Material	Galvanic Corrosion	Wall Thickness	Visual (VT-3) and/or Volumetric (RT or UT)
Loss of Material	General Corrosion	Wall Thickness	Visual (VT-3) and/or Volumetric (RT or UT)
Loss of Material	MIC	Wall Thickness	Visual (VT-3) and/or Volumetric (RT or UT)
Loss of Material	Pitting Corrosion	Wall Thickness	Visual (VT-1) and/or Volumetric (RT or UT)
Loss of Material	Selective Leaching	Wall Thickness	Hardness test (per response to RAI B2.1.13-1), Visual (VT-3) and/or Volumetric (RT or UT)
Loss of Material	Erosion	Wall Thickness	Visual (VT-3) and/or Volumetric (RT or UT)
Loss of Heat Transfer	Fouling	Tube Fouling	General or Remote Visual
Cracking	SCC	Cracks	Volumetric (RT or UT)
Loss of Preload	Stress Relaxation	Dimension Changes	Visual (VT-3)

In addition, the staff, based upon a review of the "parameters monitored element" for the One-Time Inspection Program, was unable to find a statement that indicated that the NDE inspections performed as part of this AMP would be conducted in accordance with the requirements of the ASME Code and 10 CFR Part 50, Appendix B. The staff requested the applicant to provide verification that the NDE inspections performed as part of the One-Time Inspection Program will be conducted in accordance with the requirements of the ASME Code and 10 CFR Part 50, Appendix B, or state that PBNP is taking an exception to the GALL Report and provide its technical justification.

In its response, dated July 12, 2004, the applicant stated that the NDE exams performed as a part of the One-Time Inspection Program will be conducted in accordance with the requirements of ASME Code Section XI and 10 CFR Part 50, Appendix B, except for the general or remote visual examinations. The general or remote visual examinations for loss of heat transfer due to fouling will be performed in accordance with the requirements of ASME Code Section V and 10 CFR Part 50, Appendix B.

In LRA Section B2.1.13, the applicant stated that its One-Time Inspection Program is consistent with GALL AMP XI.M32, with exceptions. The One-Time Inspection Program takes exception to the "scope of the program" and "detection of aging effects" program elements for GALL AMP XI.M32 in that examination of nonexempt small-bore ASME Code Class 1 and 2 piping will be addressed within the applicant's ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, which includes volumetric examinations performed in accordance with RI-ISI requirements.

GALL AMP XI.M32 states the program includes measures to verify that unacceptable degradation is not occurring, thereby validating the effectiveness of existing AMPs or confirming that there is no need to manage aging-related degradation for the period of extended operation. The structures and components for which one-time inspection is intended to verify the effectiveness of the AMPs have been identified in the GALL Report. Examples include small bore piping in the reactor coolant system or the feedwater system components in boiling water reactors (BWRs) and PWRs. The GALL Report includes piping less than 4 inches in diameter as small bore piping.

The staff reviewed the SER documented in a letter from NRC to PBNP, "Point Beach Nuclear Power Plant, Units 1 & 2 - Evaluation of Risk Informed Inservice Inspection Program (ML030210167)," dated July 2, 2003. The staff determined that the plant's augmented programs for FAC and high-energy break exclusion piping are not subsumed into the RI-ISI program and remain unaffected. The degradation mechanisms identified in the RI-ISI submittal included thermal fatigue, thermal transients, IGSCC, PWSCC, and FAC. These aging effects were compared with the aging effects identified in one of the RI-ISI programs (EPRI TR-106706). All aging effects addressed by the One-Time Inspection Program were found to be included in the scope of aging effects managed by the RI-ISI program. The applicant also clarified that the RI-ISI program addresses only the Class 1 and 2 piping welds.

In LRA Section B2.1.13, the applicant stated that its One-Time Inspection Program is consistent with GALL AMP XI.M33, with exceptions. The One-Time Inspection Program takes exception to the "scope of the program," "parameters monitored or inspected," and "detection of aging effects" program elements such that hardness measurements may be performed in accessible locations to confirm the absence of selective leaching and determine material properties, which can be used in component functionality assessments. The internal surfaces of susceptible components may not be accessible for hardness measurements due to the size of the component. Therefore, only visual inspections are required by the program.

GALL AMP XI.M33 states, for the "scope of the program" program element, this AMP determines the acceptability of the components that may be susceptible to selective leaching and assess their ability to perform the intended function during the period of extended operation. The GALL Report includes a one-time hardness measurement of a selected set of components to determine whether loss of material due to selective leaching is not occurring for the period of extended operation. GALL AMP XI.M33 states, for the "parameters monitored or inspected" program element that the one-time visual inspection and hardness measurement include close examination of a select set of components to determine whether selective leaching occurred and whether the resulting loss of strength and/or material will affect the intended functions of these components during the period of extended operation. Selective leaching generally does not cause changes in dimensions and is difficult to detect. However, in certain brasses it causes plug-type de-zincification, which can be detected by visual inspection. One acceptable procedure is to visually inspect the susceptible components closely and conduct Brinell hardness testing on the inside surfaces of the selected set of components to determine if selective leaching occurred. If it is occurring, an engineering evaluation is initiated to determine acceptability of the affected components for further service. Further evaluation for the "detection of aging effects" program element is documented in RAI B2.1.13-1, below.

The staff's review of LRA Section B2.1.13 identified an area 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.

During the audit, the staff conducted discussions concerning this exception with PBNP technical staff. The staff further evaluated this exception and was unable to reconcile how leaching of the subject components would be effectively managed using only visual inspection; that is, without performance of hardness testing on the inside surfaces of the selected set of components. The inability to reconcile this exception is predicated on GALL AMP XI.M33, which indicates that visual inspections are generally unable to detect leaching. However, the staff acknowledges that components with limited accessibility may be one factor in choosing the "selected set of components" upon which the hardness tests are to be performed. The PBNP exception indicates that "hardness measurements may be performed," which therefore, makes hardness testing optional.

RAI B2.1.13-1. In RAI B2.1.13-1, dated September 16, 2004, the staff requested the applicant to demonstrate that visual inspection alone will guarantee detection of leaching in cast iron and brass materials. Otherwise, the staff requested the applicant to indicate whether or not it will perform a one-time visual inspection and hardness measurement on a selected set of components, of each material type, to determine whether selective leaching occurred and whether the resulting loss of strength and/or material will affect the intended functions of these components during the period of extended operation.

In its response, dated October 15, 2004, the applicant stated that a one-time visual inspection and hardness measurement will be performed on accessible locations of a select set of components of each material type (*e.g.*, cast iron and brass) to determine whether selective leaching occurred and whether the resulting loss of strength and/or material will affect the intended functions of these components during the period of extended operation. The internal surfaces of susceptible components may not be accessible for hardness measurements due to the size of the component. Therefore, one of the factors used in choosing the selected set of components to be inspected for selective leaching will be the accessibility of the internal surface of the component for hardness testing. Hardness measurements will be performed in accessible locations to confirm the absence of selective leaching and determine material properties that can be used in component functionality assessments.

Furthermore, the applicant stated that during the AMR process it was not always possible to determine whether the cast iron components in question were constructed of gray or ductile cast iron. In many cases the material specification only stated cast iron. In these cases, PBNP conservatively assumed that the material was gray cast iron and susceptible to selective leaching. Should further material evaluation determine that the material is ductile cast iron and, therefore, not susceptible to selective leaching, these components would be removed from the selected set of components to be inspected for selective leaching.

The staff reviewed the information provided by the applicant and the RAI response discussed above, as documented in the audit and review report. On the basis of its review, the staff found this exception acceptable. The staff's concerns described in RAI B2.1.13-1 are resolved.

In LRA Section B2.1.13, the applicant stated that its One-Time Inspection Program is consistent with GALL AMP XI.M32 and GALL AMP XI.M33, with enhancements. The applicant stated that, for the "scope of the program" program element, enhancements include the creation of new implementing documents required to provide those inspections necessary to manage aging of components within the scope of license renewal. The staff considered this type of enhancement to be an administrative enhancement that does not require staff review.

Operating Experience. The staff reviewed the applicant's operating experience for the One-Time Inspection Program.

The applicant stated that the One-Time Inspection Program is a new program to be implemented before the current operating license expires. The NDE inspection methods that will be used, such as visual (or remote visual), surface or volumetric, or other established techniques, are consistent with industry practice.

The staff reviewed the information provided by the applicant, as documented in the audit and review report. The staff found that the applicant uses a database to track plant operating experience as well as industry operating experience.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. The staff concluded that the operating experience is consistent with industry practice. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the One-Time Inspection Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.13, the applicant provided the FSAR supplement for the One-Time Inspection Program. The staff reviewed these sections and the applicant's letter dated October 15, 2004 and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review, RAI response, and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.14 Open-Cycle Cooling (Service) Water System Surveillance Program

Summary of Technical Information in the Application. The applicant's Open-Cycle Cooling (Service) Water System Surveillance Program is described in LRA Section B2.1.14, "Open-Cycle Cooling (Service) Water System Surveillance Program." The applicant stated that this is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.M20, "Open-Cycle Cooling Water System."

The applicant stated that the Open-Cycle Cooling (Service) Water System Surveillance Program relies on implementation of the recommendations of GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," to ensure that the aging effects such as loss of material due to general, pitting, and crevice corrosion, microbiologically induced corrosion (MIC), and loss of heat transfer due to biological/corrosion product fouling (*e.g.*, sedimentation, silting) caused by exposure of internal surfaces of metallic components in cooling water systems to raw, untreated water will be managed for the period of extended operation. The aging effects are managed through (1) surveillance and control of biofouling, (2) verification of heat transfer by testing, and (3) routine inspection and maintenance program activities to ensure that aging effects do not impair component intended function. The applicant states that this program complies with PBNP responses to GL 89-13.

During the audit, the applicant stated that there is no lined/coated piping in the open-cycle cooling (service) water system.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In LRA Section B2.1.14, the applicant stated that its Open-Cycle Cooling (Service) Water System Surveillance Program is consistent with GALL AMP XI.M20, with exceptions. The Open-Cycle Cooling (Service) Water System Surveillance Program takes exception to the "scope of the program" program element for GALL AMP XI.M20 in that not all of the safety-related heat exchangers are tested to verify heat transfer capability by performing a heat balance test.

GALL AMP XI.M20 states that, consistent with the guidelines of GL 89-13, the open-cycle cooling water system program implements a periodic testing program for degraded heat exchanger performance in order to verify heat transfer capabilities for heat exchangers relied on to transfer heat from safety-related SSCs to the ultimate heat sink.

The applicant identified the following as in-scope components that will not receive routine heat transfer capability testing: primary auxiliary building battery room vent coolers, turbine driven auxiliary feed water pump turbine oil coolers, containment fan motor coolers, and emergency diesel generators G01/G02 coolant heat exchangers. The applicant stated that, as an alternative, these small heat exchangers are periodically flushed or cleaned, and inspected as part of regular maintenance.

The staff reviewed the regular maintenance activities that were proposed as an alternative to periodic heat transfer verification testing for each of the heat exchangers identified in the exception, as documented in the audit and review report. The applicant stated that the primary auxiliary building battery room vent coolers and emergency diesel generators G01/G02 coolant heat exchangers are inspected and, if necessary, cleaned annually, and that the turbine-driven auxiliary feed water pump turbine oil coolers and containment fan motor coolers are inspected and, if necessary, cleaned every refueling outage. In addition, selected parameters are monitored during periodic performance testing of the turbine-driven auxiliary feed water pumps and emergency diesel generators. The turbine-driven auxiliary feed water pumps bearing oil temperatures are recorded and compared against acceptance criteria and the emergency diesel generators service water outlet temperature, coolant/service water differential pressure, lube oil temperature, and coolant temperature are recorded and trended. Inspection and cleaning frequencies are adjusted if coolant temperatures trend upward.

On the basis of its review, the staff concluded that these alternatives are consistent with PBNP's responses to GL 89-13 and the applicant's proposed periodic maintenance, monitoring, and trending is an acceptable alternative to periodic testing for degraded heat exchanger performance. In addition, the staff determined that the proposed periodic inspection and cleaning/flushing activities, and component functional testing will effectively manage fouling and scaling aging effects and ensure that heat transfer capabilities are maintained. On this basis, the staff found the exception acceptable.

In LRA Section B2.1.14, the applicant stated that its Open-Cycle Cooling (Service) Water System Surveillance Program is consistent with GALL AMP XI.M20, with enhancements. The applicant stated that, for the "detection of aging effects" program element, enhancements include (1) verification that the implementing documents for activities contain a reference or other link, (2) clarification of GL 89-13 commitments regarding the emergency diesel generator G01/G02 coolant heat exchangers, and (3) revisions to existing call-ups to ensure evaluations take place for the management of aging effects. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

Operating Experience. The staff reviewed the applicant's operating experience for the Open-Cycle Cooling (Service) Water System Surveillance Program.

The applicant stated that heat exchangers have experienced erosion/corrosion of end bells, biofouling build-up, and silt accumulation. Erosion/corrosion has also been experienced at or near throttled valves. Zebra mussels have been found and are controlled by the chlorination system, copper ion generator treatment, and periodic cleaning of the heat exchanger tubes. Piping systems have experienced corrosion, pitting, MIC, and sedimentation build-up especially in low flow areas and stagnant dead legs off the main flow stream. These are controlled by flushing, the chlorination system, and inspections. Cavitation/erosion of components is monitored by using established NDE methods and components have been repaired and/or replaced, as necessary.

The applicant also stated that plant-specific operating experience was reviewed and revealed that condition reports and work orders were initiated to repair system leaks and/or to investigate component wall thinning due to corrosion. Deficiencies found in service water system components were addressed via the corrective action program such that these deficiencies are corrected so that they will not impede the component's intended function.

Furthermore, the applicant stated that a review of NRC inspection reports, QA audit/surveillance reports, and self-assessments since 1999 revealed no other issues or findings that could impact the effectiveness of the Open-Cycle Cooling (Service) Water System Surveillance Program. As additional operating experience is obtained, lessons learned may be used to adjust this program.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. The staff concluded that the operating experience is consistent with industry practice. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Open-Cycle Cooling (Service) Water System Surveillance Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.14, the applicant provided the FSAR supplement for the Open-Cycle Cooling (Service) Water System Surveillance Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.15 Reactor Coolant System Alloy 600 Inspection System Program

Summary of Technical Information in the Application. The applicant's Reactor Coolant Alloy 600 Inspection System Program is described in LRA Section B2.1.16, "Reactor Coolant System Alloy 600 Inspection System." In the LRA, the applicant stated that this is a new program that is consistent, with exceptions and enhancements, with GALL AMP XI.M11, "Nickel Alloy Penetrations."

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.16, regarding the applicant's demonstration of the Reactor Coolant Alloy 600 Inspection System to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff's original basis for inspecting Alloy 600 reactor vessel head (RVH) penetration nozzles in U.S. PWR is provided in GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Head Penetrations," dated, April 1, 1997. Between November 2000 and April 2001, subsequent to the issuance of GL 97-01, reactor coolant pressure boundary (RCPB) leakage was identified from the RVH penetration nozzles of four U.S. PWR-design light water reactor facilities. Supplemental examinations of the degraded nozzles indicated the presence of circumferential cracks in four of the CRDM nozzles. These cracks initiated from the outer surface of the nozzle, either in the associated J-groove weld or heat-affected-zone, and not from the inside surface of the nozzle, as was assumed in the industry responses to GL 97-01. These cracks penetrated through the nozzles and were the first identified instances of circumferential cracking in U.S. RVH penetration nozzles. In NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head (RVH) Penetration Nozzles," issued on August 3, 2001, the staff discussed the generic safety significance and impact of these cracks on RVH penetration nozzles and recommended that enhanced visual examination or volumetric examination methods be used for the inspection of RVH penetration nozzles.

In March 2002, during a refueling outage at the Davis-Besse Nuclear Power Station, the licensee reported the occurrence of reactor coolant leakage from an RVH penetration that resulted in significant boric-acid-related wastage of the RVH. The wastage affected the entire thickness of a localized area of the RVH around a penetration nozzle with the exception of the RVH cladding. On March 18, 2002, the NRC issued Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," to owners of PWR designs, requesting that the licensees address the impact of the Davis-Besse event on the structural integrity of their RVHs and associated penetration nozzles. On August 9, 2002, the staff issued Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," to address additional technical issues resulting from the Davis-Besse event. In Bulletin 2002-02, the staff specifically suggested that further augmented inspections, more comprehensive than those suggested in Bulletin 2001-01, be performed on RVH penetration nozzles. On February 11, 2003, the staff issued Order EA-03-009, "Issuance of Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," to further define the frequency and extent of examination of nickel-based alloys and welds in the RPV heads due to PWSCC. On August 21, 2003, the staff issued Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," to advise licensees that RPV lower head inspections may need to be supplemented with additional measures to assure that reactor coolant pressure boundary (RCPB) leakage is detected. On February 23, 2004, the staff issued First Revised Order EA-03-009, to modify the inspection requirements for reactor pressure vessel heads at PWRs.

During V.C. Summer refueling outage 12, in October 2000, a through-wall crack was identified in the RV hot-leg nozzle safe-end weld. This weld was fabricated from Alloy 82/182 weld material. NRC Information Notices (IN) 2000-17 and 2000-17, Supplement 1, dated October 18, 2000, and November 16, 2000, respectively, provide details of the V.C. Summer RV hot-leg nozzle weld cracking event. Since the V.C. Summer main coolant loop weld cracking event involves Alloy 82/182 weld material, the staff has been addressing the effect of primary water stress corrosion cracking (PWSCC) on Alloy 82/182 piping welds on a generic basis for all currently operating PWR plants. To resolve this current operating issue, the industry is taking the initiative to (1) develop overall inspection and evaluation guidance; (2) assess the current inspection technology; and (3) assess the current repair and mitigation technology. An interim industry report, "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plants (MRP-44), Appendix 1: Alloy 82/182 Pipe Butt Welds," was published in April 2001 to justify the continued operation of PWR plants while the industry completes the development of the final report. The staff documented its acceptance of this interim report in an SE dated June 14, 2001. The final industry report, "Alloy 82/182 Pipe Butt Weld Safety Assessment for U.S. PWR Plant Designs (MRP-113)," was issued in July 2004. Pending the staff's review of this report and additional UT inspection data from piping involving Alloy 82/182 weld material from the industry, the staff is pursuing resolution of this current operating issue pursuant to 10 CFR Part 50.

The aging of RVH penetration nozzles and other Class 1 components made from nickel-based alloys due to PWSCC is an emerging issue that is currently being evaluated and resolved by the NRC and external stakeholders. The staff assessed whether the applicant's AMP accounted for the effects of the Davis-Besse event and other applicable operating experience.

The staff reviewed the Reactor Coolant System Alloy 600 Inspection System Program against the AMP elements found in the GALL Report, SRP-LR Section A.1.2.3, and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience). The Reactor Coolant System Alloy 600 Inspection System Program takes exceptions to the following program elements: (1) scope of the program, (4) detection of aging effects, (5) monitoring and trending, and (7) operating experience.

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

LRA Section B2.1.16 states that the Reactor Coolant System Alloy 600 Inspection Program is consistent with the GALL Report, with enhancements. The applicant stated that enhancements will include development of new implementing documents to meet the commitments made in response to NRC Bulletins 2002-02, 2003-02 and the requirements of NRC Order EA-03-009. The staff considered this type of enhancement to be an administrative enhancement that does not require staff review.

(1) Scope of the Program - The applicant stated that the Reactor Coolant System Alloy 600 Inspection Program scope included the control rod drive mechanism (CRDM) adapter tubes, reactor vessel bottom head instrumentation penetrations and associated Inconel attachment welds to the reactor vessel closure head or bottom head, Inconel 82/182 butt welds of the Alloy 600 CRDM adapter tube and bottom-mounted instrumentation nozzles to stainless steel safe ends, Unit 2 SG vent nozzles and the associated Inconel 152 welds, and the Unit 2 Inconel 82/152 SG primary nozzle-to-safe end welds.

The staff noted that the applicant made commitments specific to degradation involved with the Alloy 600 material and degradation in the RPV head J-groove welds. PBNP committed to performing bare metal visual examinations of the reactor pressure vessel head and nozzles of Units 1 and 2 in response to NRC Bulletins 2001-01 and 2002-02 and indicated compliance with Order EA-03-009. Based on the discussion above, the staff has concerns regarding the applicant's involvement and developing issues surrounding the 82/182 alloy welds and other Alloy 600 successors. Secondly, the applicant stated that enhancements are scheduled for completion consistent with the commitments made in the response to NRC Bulletins 2002-02 and 2003-02 and the requirements of NRC Order EA-03-009, or prior to the period of extended operation, as applicable.

The staff's review of LRA Section B2.1.16 identified an area 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.

RAI 2.1.16-1. In RAI 2.1.16-1, dated November 17, 2004, the staff requested the applicant to provide a commitment to assure that interim report "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plants (MRP-44), Appendix 1: Alloy 82/182 Pipe Butt Welds," and its final version will be used as part of the basis for the Reactor Coolant System Alloy 600 Inspection Program. The commitment should state that the Reactor Coolant System Alloy 600 Inspection Program will be submitted 24 to 36 months prior to the period of extended operation for staff review and approval to determine if the program demonstrates the ability to manage the effects of aging pursuant to 10 CFR 54.21(a)(3).

In its response, dated January 25, 2005, the applicant committed to use the interim report "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plant (MRP-44), Appendix 1: Alloy 82/182 Pipe Butt Welds," and its final version as part of the basis for the Reactor Coolant System Alloy 600 Inspection Program. The applicant further committed to submit the Reactor Coolant System Alloy 600 Inspection Program to the NRC for staff review and approval 24 to 36 months prior to the period of extended operation.

On the basis of its review and the RAI response discussed above, the staff found this acceptable. The applicant committed to submit the subject program 24 to 36 months prior to the period of extended operation. The staff's concern in RAI 2.1.16-1 is resolved.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - The applicant stated that the program credited the Water Chemistry Control Program for monitoring and control of reactor coolant water chemistry to mitigate PWSCC. This element is consistent with the corresponding NUREG-1801 AMP element that recommends the use of the Water Chemistry Control Program to mitigate cracking.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - The applicant stated that the Reactor Coolant System Alloy 600 Inspection Program incorporates routine inspections performed under the ISI program and augmented inspections capable of detecting and sizing non-through-wall cracks. For vessel head penetration (VHP), augmented visual inspections for leakage and volumetric and/or surface exams are performed in accordance with regulatory requirements and commitments. This element is consistent with the corresponding NUREG-1801 AMP element that recommends the use of the ISI Program to monitor for cracking. In addition, the applicant stated that testing will be in accordance with regulatory requirements. The staff notes that the current regulatory requirements under First Revised Order EA-03-009 exceed the ASME Code requirements.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.3. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - The applicant stated that it differed from the guidance in the GALL Report in that it was using the methodology prescribed by NRC Order EA-03-009 rather than the model referenced in the GL 97-01 response. In addition, the enhancements to the program include the development of new implementing documents to meet the commitments made in response to NRC Bulletins 2002-02 and 2003-02. Since these regulatory documents pertain primarily to nickel-based alloys in RPV heads, the applicant indicated that performance of susceptibility assessments and development of corrective action plans and/or inspections will be done for nickel-based components and welds not addressed under the evaluations for the RPV head.

INs 2000-17 and 2000-17, Supplement 1, dated October 18, 2000, and November 16, 2000, respectively, provide details of the V.C. Summer RV hot-leg nozzle weld cracking event. Since the V.C. Summer main coolant loop weld cracking event involves Alloy 82/182 weld material, the staff has been addressing the effect of primary water stress corrosion cracking (PWSCC) on Alloy 82/182 piping welds on a generic basis for all currently operating PWR plants. To resolve this current operating issue, the industry is taking the initiative to (1) develop overall inspection and evaluation guidance; (2) assess the current inspection technology; and (3) assess the current repair and mitigation technology. An interim industry report, "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plants (MRP-44), Appendix 1: Alloy 82/182 Pipe Butt Welds," was published in April 2001 to justify the continued operation of PWR plants while the industry completes the development of the final report. The staff documented its acceptance of this interim report in a SE dated June 14, 2001. The final industry report, "Alloy 82/182 Pipe Butt Weld Safety Assessment for U.S. PWR Plant Designs (MRP-113)," was issued in July 2004. Pending the staff's review of this report and additional UT inspection data from piping involving Alloy 82/182 weld material from the industry, the staff is pursuing resolution of this current operating issue pursuant to 10 CFR Part 50. Based on its response to RAI 2.1.16-1, dated January 25, 2005, and its associated commitment discussed under the scope of the program, the staff concluded that this element is acceptable. The staff's concern described in RAI 2.1.16-1 is resolved.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - The applicant stated that periodic RPV head inspections are performed as required to meet commitments made in response to NRC Bulletin 2002-02 and the requirements of NRC Order EA-03-009. Periodic inspection of the lower RPV dome will be conducted as described in PBNP's response to NRC Bulletin 2003-02. Inspections of other components are based on the results of the susceptibility assessment and corrective action plan. This element provides a more recent and up-to-date methodology than that suggested by the GALL Report that discusses GL 97-01.

The staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - The applicant stated that indications detected will be evaluated in accordance with ASME Code Section XI requirements. Additionally, if non-through-wall cracks are detected by a volumetric inspection, the evaluation of the component's acceptability for continued service will consider the most current crack growth rate information. This is consistent with the GALL Report, which recommends evaluation in accordance with ASME Code Section XI. Also, NUREG-1801 recommends that if there have been significant changes since the applicant's response to GL 97-01, the applicant provide references to appropriate industry model revisions or provides updated information on crack initiation and crack growth data and models.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.6. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - The applicant stated that extensive industry operating experience had been reviewed in developing the Reactor Coolant System Alloy 600 Inspection Program. The applicant referred to PWSCC cracking in 82/182 alloy piping butt weld (V.C. Summer), severe degradation in an RPV head (Davis Besse) and axial cracking in reactor vessel bottom-mounted instrumentation (BMI) penetrations (South Texas). The applicant also performed a justification for continued operation, and revised existing guidance documents to provide more direction for responding to increasing RCS leakage, and inspection of the Units 1 and 2 reactor vessel heads.

The staff's review of LRA Section B2.1.16 identified an area in which additional information was necessary to complete the review of this program element. The applicant responded to the staff's RAI as discussed below.

<u>RAI 2.1.16-2</u>. In RAI 2.1.16-2, dated November 17, 2004, the staff requested the applicant to discuss its review of industry/plant operating experience and how it will equate to the continued operation of the existing Units 1 and 2 RPV heads. If the heads are to be replaced, please discuss your plans for the monitoring of the heads in

accordance with current industry events, Owner's Groups activities and existing NRC regulations or orders.

In its response, dated January 25, 2005, the applicant stated that the RPV heads would be replaced during each unit's upcoming refueling outage in 2005. Furthermore, the applicant stated that the replaced RPV heads would be inspected in accordance with the requirements of NRC Order EA-03-009, "Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," revised February 20, 2004. Finally, the applicant stated that NMC is actively participating with the industry through the EPRI MRP efforts to develop long-term inspection procedures for reactor vessel closure heads and their penetrations for U.S. pressurized water reactor plants. The staff concluded that the replacement of the RPV heads along with the commitment to monitor the new heads in accordance with the most recent MRP guidelines and Order EA-03-009 provided the most conservative and up-to-date methodology for inspecting due to PWSCC in CRDM penetrations. Therefore, the staff considers the applicant's response to RAI 2.1.16-2 acceptable. The staff's concern described in RAI 2.1.16-2 is resolved.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

<u>FSAR Supplement</u>. In LRA Section A15.2.1.16, the applicant provided the FSAR supplement for the Reactor Coolant System Alloy 600 Inspection Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review, the RAI responses discussed above, and its audit of the applicant's program, 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 concluded that the applicant's commitment to submit the Reactor Coolant System Alloy 600 Inspection Program 24 to 36 months prior to the period of extended operation is acceptable. This program will demonstrate that the effects of aging, associated with the Alloy 600 Class 1 components, will be adequately managed. The staff also reviewed the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 Reactor Vessel Internals Program

<u>Summary of Technical Information in the Application</u>. The applicant's Reactor Vessel Internals Program is described in LRA Section B2.1.17, "Reactor Vessel Internals Program." In the LRA, the applicant stated that this is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.M13, "Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)," and GALL AMP XI.M16, "PWR Vessel Internals."

The applicant stated that the Reactor Vessel Internals Program manages the aging effects for both non-bolted and bolted reactor vessel internal (RVI) components. The program provides for: (1) inservice inspection (ISI) in accordance with ASME Code Section XI requirements including supplemental examinations on the leading locations of non-CASS components with respect to irradiation-assisted stress corrosion cracking (IASCC) and irradiation embrittlement and the leading locations of CASS components with respect to fluence and thermal aging embrittlement screening criteria; (2) evaluations that will identify leading locations with respect to IASCC and irradiation embrittlement and thermal aging embrittlement; (3) the development and implementation of appropriate nondestructive examination (NDE) techniques and examination schedule for these locations; (4) baffle-former and barrel-former bolt evaluations that will determine the acceptability of the current arrangement or if ultrasonic examination and/or replacement of these bolts is necessary; and (5) monitoring and control of reactor coolant water chemistry in accordance with the Water Chemistry Control Program to mitigate SCC or IASCC.

The applicant stated that this program is credited by the Bolting Integrity Program for the inspection of bolting internal to the RV. In addition to the requirements of ASME Code Section XI, Subsection IWB, this program monitors for loss of preload caused by stress relaxation of bolted joints and specifically addresses cracking in baffle/barrel former bolts. This program also credits the One-Time Inspection Program for the management of stress relaxation of the lower internals hold-down spring.

Furthermore, the applicant stated that it will actively participate in industry groups such as the EPRI MRP RI-ITG and the Westinghouse Owners' Group, who are studying RVI materials degradation issues. The applicant also will implement NRC-approved industry activities resulting from the MRP efforts, as appropriate, to manage any applicable aging effects identified through the MRP effort. The applicant will continue to monitor industry research on the significance of void swelling and augmented examinations for void swelling based on the results and recommendations of the industry research.

In the LRA and in NMC clarification letter, dated July 12, 2004, the applicant stated its Reactor Vessel Internals Program is based on the following industry initiatives and attributes:

- NMC will continue to participate in the industry's initiatives intended to clarify the nature and extent of aging mechanisms potentially affecting RVIs.
- NMC will incorporate the results of these initiatives (to the extent that they are applicable to the PBNP RVIs) into the scope, inspection requirements (including inspection locations, methods, qualifications, and frequencies), acceptance criteria, and corrective actions for the Reactor Vessel Internals Program.
- NMC will submit an inspection plan for the PBNP Reactor Vessel Internals Program for NRC review and approval at least two years prior to entering the period of extended operation.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.17 regarding the applicant's demonstration that the Reactor Vessel Internals Program will ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Reactor Vessel Internals Program against the AMP elements found in the GALL Report, SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of the 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience). The PBNP Reactor Vessel Internals Program takes exceptions to the following program elements: (1) scope of the program, (4) detection of aging effects, (5) monitoring and trending, and (6) acceptance criteria.

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of the Program - The applicant stated that the Reactor Vessel Internals Program is an existing program credited with the management of the following aging effects (1) crack initiation and growth due to irradiation-assisted stress corrosion cracking (IASCC); (2) loss of fracture toughness due to irradiation embrittlement, thermal embrittlement, or void swelling; and (3) changes in material properties as a result of void swelling.

The applicant identified reactor vessel internals (RVIs) major components as upper internals and lower internals. The following RVI components are within the scope of the Reactor Vessel Internals Program.

Lower internals major components:

- baffle and former plates
- baffle-former and barrel-former bolts
- bottom-mounted instrumentation columns
- core barrel flange
- core barrel outlet nozzles
- diffuser plate
- lower core plate
- lower support forging
- lower support plate column
- secondary core support
- thermal shield
- upper and lower core barrel

Upper internals major components:

- control rod guide tubes
- upper core plate
- upper instrumentation columns and supports
- upper support columns
- upper support plate

Virtually all these components are fabricated from various types of wrought austenitic stainless steel; however, a few components are fabricated from CASS. Unit 1 guide tube split pins are fabricated from nickel-based alloy X-750. Unit 2 split pins were replaced during the 2005 refueling outage. The new split pins are fabricated from cold-worked 316 stainless steel.

The applicant's program relies on the ASME Code Section XI examinations of the RVIs to detect the applicable aging effects. This program credits the ASME Code Section XI, Subsection IWB, IWC, and IWD Inservice Inspection Program (ISI) for the ISI examinations of the RVIs. The applicant recognizes that for some components the VT-3 examination required by ASME Code Section XI may not be adequate to detect the effects before the component's intended function is compromised. The applicant stated that the need for augmented examinations will be determined by evaluations of the susceptibility of each RVI component to the applicable aging effects that require aging management. The applicant also stated that in addition to industry and plant-specific experience, fluence, temperature, and stress analyses may be used as inputs to the susceptibility evaluations.

For CASS components that are part of the RVIs, PBNP will use 1×10^{17} n/cm^2 (E > 1.0 MeV) as its threshold value for initiation of neutron irradiation embrittlement. This criterion is in line with the GALL's recommendation. The applicant stated that if the fluence remains below 1×10^{17} n/cm^2 (E > 1.0 MeV), the significance of thermal aging will be determined by comparison with the screening criteria, based on delta ferrite content, molybdenum content, and casting method, as described in NUREG-1801, Section XI.M13.

The Reactor Vessel Internals Program takes exception to this program element. The GALL Report references ASME Code Section XI, Subsection IWB, 95A96 for the inservice inspections of RVIs. PBNP currently uses ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, 98A00. Section 50.55a(g)(4)(iv) of 10 CFR requires that inservice examination of components may meet the requirements set forth in subsequent editions and addenda that are incorporated by reference in 10 CFR 50.55a(b) subject to the limitations and modifications listed in 10 CFR 50.55a(b) and subject to NRC approval. The staff accepts the applicant's use of the later version of the ASME Code considering: (1) use of the later version of the ASME Code as permitted by 10 CFR 50.55a, and (2) the applicant's commitment of participating in industry initiatives and submittal of inspection program for NRC approval 24 months prior to entering the period of extended operation.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.1. As discussed above, the staff concluded that this program attribute, including its associated exceptions, is acceptable.

(2) Preventive Actions - The applicant stated that the Water Chemistry Control Program is credited for monitoring and control of reactor coolant water chemistry to prevent or mitigate the effects of SCC and IASCC. Additionally, the guide tube split pins in Unit 1 have all been replaced with pins made from the same alloy with a more SCC-resistant heat treatment. In Unit 2, the pins on two guide tubes were replaced and the remaining pins were verified to have been solution heat treated above 1800 °F, although it is assumed that they are still susceptible to SCC because the initial installation torque was substantially higher than that used in the replacements. The Unit 2 split pins were replaced during the 2005 refueling outage. The new split pins are fabricated from cold-worked 316 stainless steel. A portion of the Unit 2 baffle former bolts have been replaced with a more crack-resistant material. For RVI CASS components, the program

consists of evaluations and inspections. There are no preventive actions to mitigate thermal aging, neutron irradiation embrittlement, or void swelling.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - The applicant stated that the program monitors for cracking, loss of fracture toughness, loss of bolted joint preload, wear, and change of dimensions through ASME Code Section XI examinations and augmented NDEs.

The program monitors the effects of loss of fracture toughness of components by identifying the CASS materials that either have a neutron fluence of greater than 10^{17} n/cm^2 or are determined to be susceptible to thermal aging embrittlement. For these components, PBNP will evaluate the need for, and the characteristics of, an augmented examination. As an alternative to an augmented examination, a mechanical loading assessment may be conducted. This element is consistent with the corresponding GALL Report program element.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.3. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - The applicant stated that exception to this NUREG-1801 AMP element was taken. NUREG-1801 provides a specific example of an acceptable supplemental or enhanced examination as VT-1 examination with .0005 inch resolution. The applicant's program does not specify resolution requirements for enhanced VT-1 examination, but rather requires examination methods sufficient to detect a crack of such size that crack growth during the interval until the next examination will not result in a crack of critical size or larger.

The applicant stated that visual examinations to detect cracking, loss of preload, and wear are used. The type of visual examination utilized will be, as a minimum, the VT-3 examination specified by ASME Code Section XI, Subsection IWB, Category IWB, Category B-N-3. Augmented examinations for cracking may consist of VT-1, enhanced VT-1 examinations, or a volumetric examination when warranted by the size and location of the crack that must be detected to preserve intended functions. For baffle-former bolts and other bolts that are largely inaccessible for visual examination, ultrasonic testing or other appropriate NDE technique will be used to detect cracking. The applicant confirmed in the LRA "for baffle-former and other bolts that are largely inaccessible for visual examination, ultrasonic testing (UT) or other appropriate NDE technique will be used to detect cracking." PBNP also confirmed that it will evaluate the need for an augmented examination covering portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility, neutron fluence, and cracking.

The applicant committed to: (1) examination methods sufficient to detect a crack of such size that crack growth during the interval will not result in a crack of critical size or larger, and (2) participate in industry initiatives and submittal of inspection program for NRC approval 24 months prior to entering the period of extended operation. Therefore, the staff concluded that this exception is acceptable.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - The applicant stated that exception to this corresponding NUREG-1801 AMP element was taken. The GALL Report specifies examination schedules in accordance with ASME Code Section XI IWB-2400, which requires core support structures to be inspected once during each 10-year interval. The applicant stated, "while this applies to the VT-3 examination, some augmented examinations may be performed at a different frequency or only one-time based on the susceptibility evaluations and examinations result."

The applicant currently uses the VT-3 examination pursuant to ASME Code Section XI, Subsection IWB, Category B-N-3 once per 10-year interval on each accessible part of the RVIs. The applicant also planned to schedule either periodic or one-time augmented examinations for cracking in components susceptible to cracking or loss of fracture toughness, and ultrasonic examinations of baffle-former bolts for cracking. The scheduling of future augmented examinations will depend on the results of the initial examination.

PBNP's inspection frequency is based on susceptibility evaluations and examination results and, in essence, meets the intent of NUREG-1801 AMP elements. In addition, the applicant committed to participate in industry initiatives and submittal of inspection program for NRC approval 24 months prior to entering the period of extended operation. Therefore, the staff concluded that this exception is acceptable.

The staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - The applicant stated that the relevant conditions of degradation detected will be evaluated in accordance with ASME Code Section XI IWB-3100, which refers to acceptance standards contained in ASME Code Section XI IWB-3400 and IWB-3500. The criteria of IWB-3500 will be used for CASS components with flaw tolerance evaluations in accordance with the ASME Code Section XI IWB-3640 procedure for submerged arc welds, with the modification for delta ferrite content as required by IWB-3641. However, any of the acceptance methods of ASME Code Section XI IWB-3132 may be used (*i.e.*, volumetric or surface examination, repair/replacement, analytical evaluation).

The applicant took exception to this NUREG-1801 AMP element. GALL AMP XI.M16 refers to the ASME Code Section XI, 95A96. PBNP uses ASME Code Section XI, 98A00.

The staff accepts the applicant's use of the later version of the ASME Code considering: (1) use of the later version of the ASME Code as permitted by 10 CFR 50.55a, and (2) the applicant's commitment to participate in industry initiatives, and (3) submittal of its inspection program for NRC approval 24 months prior to entering the period of extended operation.

Since it has been adopted in the GALL Report, use of industry research studies and activities on age-related degradation of RVI components may be used as an alternative basis for determining which age-related degradation mechanisms are applicable to RVIs and what types of examinations are necessary to manage these mechanisms. This is a process-oriented approach to aging management that will ensure that the inspections proposed for RVIs are those that the industry research studies have demonstrated are necessary to maintain the structural integrity or functionality of the components. NRC's review of the recommended activities is an integral part of the industry initiative process. The staff used this alternative in evaluating the exceptions identified in program attributes.

However, any proposal to use the industry's research studies and activities on RVIs as the basis for aging management must be coupled with: (1) a commitment to implement the recommendations that result from these studies and activities, and (2) a commitment to submit the inspection plan for the RVIs to the NRC for review and approval prior to the period of extended operation.

The LRA and the clarification letter, dated July 12, 2004, confirmed that:

- NMC will continue to participate in the industry's initiatives intended to clarify the nature and extent of aging mechanisms potentially affecting RVIs.
- NMC will incorporate the results of these initiatives (to the extent that they are applicable to the PBNP RVIs) into the scope, inspection requirements (including inspection locations, methods, qualifications, and frequencies), acceptance criteria, and corrective actions for the Reactor Vessel Internals Program.
- NMC will submit an inspection plan for the PBNP Reactor Vessel Internals Program for NRC review and approval at least two years prior to entering the period of extended operation.

Therefore, the staff concluded that the applicant's LRA commitment is acceptable. PBNP will: (1) apply acceptable industry guidelines that will ensure that only those inspections will be used that are capable of detecting degradation prior to a loss of component intended function; (2) allow the staff to review the applicant's inspection plans for the RVI as based on the industry recommendations, and (3) provide the staff an opportunity to resolve with the applicant any issues that may arise with the inspection plan.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.6. As discussed above, the staff found that the use of a later version of the ASME Code is acceptable. The staff concluded, therefore, that this program attribute is acceptable.

(10) Operating Experience - The applicant stated that industry operating experience has been reviewed during the development of the Reactor Vessel Internals Program. The experience reviewed includes IN 98-11, "Cracking Of Reactor Vessel Internal Baffle Former Bolts In Foreign Plants," and IN 84-18, "Stress Corrosion Cracking in PWR Systems." Most of the industry operating experience reviewed involved cracking of austenitic stainless steel baffle-former bolts, or SCC of high-strength internals bolting. SCC of guide tube split pins has also been reported.

A review of plant-specific operating experience with RVIs reveals that PBNP responded to industry operating experience regarding RVI degradation. Two examples that demonstrate PBNP's response to industry operating experience with RVIs are augmented examination and replacement of guide tube split pins and augmented examination and replacement of baffle-former bolts. Guide tube split pins were replaced in their entirety in Unit 1 and partially in Unit 2 in response to SCC failures of these pins in other Westinghouse units. A more SCC-resistant heat treatment was applied to the replacement pins. An augmented examination via UT was conducted on the baffle-former bolts of Unit 2. The UT examination identified a number of bolts with indications indicative of crack-like flaws. A number of bolts sufficient to guarantee the structural margins of the baffle-former joints were replaced, including all bolts with UT indications. The replacement bolts are fabricated from a more IASCC-resistant material; however, during the 2005 refueling outage, PBNP replaced all Unit 2 split pins with split pins fabricated from cold-worked 316 stainless steel. PBNP will participate in the EPRI RI-ITG, which is engaged in ongoing research into aging effects of RVIs and provides guidance to utilities on corrective actions for these aging effects. PBNP also participates in Westinghouse Owner's Group activities related to RVIs.

A review of NRC inspection reports, QA audit/surveillance reports, and self-assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Reactor Vessel Internals Program. As additional operating experience is obtained, lessons learned may be used to adjust this program. This element is consistent with the corresponding NUREG-1801 AMP elements.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in the GALL Report and SRP-LR Appendix A.1.2.3.10. The staff concluded that this program attribute is acceptable.

<u>FSAR Supplement</u>. In LRA Section A15.2.17, the applicant provided the FSAR supplement for the Reactor Vessel Internals Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found that the commitment to the Reactor Vessel Internals Program acceptable, as required by 10 CFR 54.21(d).

<u>Conclusion</u>. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.17 Reactor Vessel Surveillance Program

Summary of Technical Information in the Application. The applicant's Reactor Vessel Surveillance Program is described in LRA Section B2.1.18, "Reactor Vessel Surveillance Program." In the LRA, the applicant stated that this is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.M31, "Reactor Vessel Surveillance."

The applicant stated that its Reactor Vessel Surveillance Program, as modified by its supplemental letters dated September 10 and October 25, 2004, manages the aging effect of reduction of fracture toughness due to neutron embrittlement of the low-alloy steel reactor vessels. This program includes: (1) capsule insertion, withdrawal and materials testing/evaluation, (including upper shelf energy and increase in transition temperature, RT_{NDT} determinations), (2) fluence and uncertainty calculations, (3) monitoring of effective full power years (EFPY), and (4) determination of impact on pressure-temperature limitations and on low temperature overpressure set points (LTOP). The applicant stated that the AMP applies the methodology of Regulatory Guide (RG) 1.190 for fluence calculations and determinations. This RG provides the NRC-recommended methodology for performing "best estimate" fluence calculations.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.18, regarding the applicant's demonstration of the Reactor Vessel Surveillance Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff's evaluation of the Reactor Vessel Surveillance Program is based on its review of the program description in LRA Section B2.1.18. The staff's criteria for accepting the Reactor Vessel Surveillance Program are based on both conformance with GALL AMP XI.M31 and compliance with the applicable requirements of 10 CFR Part 50, Appendix H.

The program discussion in GALL AMP XI.M31 is not currently based on the staff's recommendations of the 10 program attributes that should be included in Reactor Vessel Surveillance Program, but rather on general recommendations of how these surveillance programs are expected to comply with the requirements of 10 CFR Part 50, Appendix H, and should be modified, as applicable, to address the increases in neutron fluences projected for the period of extended operation. Because the applicant considered the Reactor Vessel Surveillance Program to be an existing plant-specific program for Units 1 and 2, it included a description of the 10 program elements in LRA Section B2.1.18.

The staff reviewed the Reactor Vessel Surveillance Program against the AMP elements found in the GALL Report, SRP-LR Section A.1.2.3 and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience). The PBNP Reactor Vessel Surveillance Program takes exceptions to the following program element: (6) acceptance criteria.

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

LRA Section B2.1.18, as modified by a supplemental letter dated October 25, 2004, states that the Reactor Vessel Surveillance Program is consistent with GALL, with enhancements. The applicant stated that enhancements include revisions to plant procedures to clarify organizational responsibilities, describe the plan/schedule for removal, testing and evaluation of surveillance capsules, and to evaluate fracture toughness margin through the period of extended operation. The staff considered this type of enhancement as an administrative enhancement which does not require staff review.

(1) Scope of the Program - The applicant stated that the Reactor Vessel Surveillance Program consists of activities that manage the aging effects for components in the reactor vessel. The Reactor Vessel Surveillance Program only applies to the Units 1 and 2 reactor pressure vessels. Reactor Vessel Surveillance Programs, which are designed and implemented in accordance with 10 CFR Part 50, Appendix H, use testing of RV surveillance capsule test specimens as the basis for monitoring for neutron irradiation-induced embrittlement in base metals (plate or forgings) and welds that are located in the beltline region of low-alloy steel or carbon steel RVs. The original PBNP surveillance program consisted of six surveillance capsules in each unit attached to the outside of the RVIs thermal shield. Each capsule contained mechanical test specimens, Charpy V-Notch specimens, dosimetry, and thermal monitors. The mechanical test specimens were fabricated from material representative of the PBNP RVs. To date, four surveillance capsules have been removed and tested from each unit's RV. One of the standby capsules has also been removed from each unit's RV and is being stored at PBNP.

The applicant stated that the original surveillance capsules did not contain the most limiting material with respect to embrittlement. A replacement surveillance capsule containing materials closely matching the limiting materials for both Units 1 and 2 was installed in the Unit 2 RV during the 2002 refueling outage. The newly installed capsule will be withdrawn during an outage at which it accumulates a fluence equivalent to the 60 calendar-year vessel fluence. Data from an integrated surveillance program that includes all PWRs with RVs fabricated by B&W will also be used to predict embrittlement of the RV limiting beltline material. However, the applicant also stated that since the spare capsules remaining in both Units 1 and 2 RVs do not contain the most limiting materials, there are no plans to withdraw these capsules. By keeping the capsules in the vessel, the capsules will experience much higher exposure and would not provide meaningful data. The program discussion in GALL AMP XI.M31 suggests to withdraw one capsule at an outage in which the capsule receives neutron fluence exposure equivalent to the 60-year fluence and test the capsule in accordance with the requirements of ASTM E 185. The GALL Report also suggests that other standby capsules be removed and placed in storage. These standby capsules would be available for reinsertion into the reactor if needed. The applicant stated that it has no plan to withdraw the last capsules from the PBNP vessels.

The staff's review of LRA Section B2.1.18 identified an area 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.

RAI B2.1.18-1. In RAI B2.1.18-1, dated November 17, 2004, the staff requested the applicant to justify its decision of not removing the capsules from the vessels.

In its response, dated January 25, 2005, the applicant stated that there are no current plans to remove the standby capsules from the reactor vessels. The standby capsules may be removed at some time in the future to support industry needs. Also, the lead factor for these remaining capsules is low enough to allow extended neutron exposure. Removal of these capsules will not directly support demonstration of adequate upper shelf energy (USE) and pressurized thermal shock (PTS) evaluations for the Units 1 and 2 RVs, and consequently removal was not required in the AMP. The Reactor Vessel Surveillance AMP requires all withdrawn surveillance capsules, not discarded as of August 31, 2000, to be placed in storage for purposes of future use, if necessary. The staff agreed with the applicant's approach; removal of these capsules is not necessary at this point.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - The applicant stated that the surveillance program determines neutron embrittlement of RV materials that will be used in evaluating for USE and its impact on pressure-temperature limits for 60 years. However, there are no preventive or mitigative actions associated with the RV surveillance removal and evaluation program, nor did the staff identify a need for such actions.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - The applicant stated that the program monitors the effects of neutron irradiation on the Units 1 and 2 RV beltline materials. Fracture toughness of beltline materials is indirectly monitored through measurement of the impact energy of Charpy V-notch specimens, made from representative materials from the PBNP RV beltline regions. The surveillance capsules also contain neutron dosimetry that monitors the amount of neutron fluence received by the test specimens. Fracture toughness of PBNP RV beltline materials were monitored using the Charpy V-notch specimens and neutron fluence was monitored using the neutron dosimeters. Therefore, the staff concluded that the applicant satisfied the monitoring criteria as recommended in the GALL Report.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.3. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - The applicant stated that aging effects are detected through testing of surveillance materials. Charpy V-notch tests are performed to determine the decrease in USE and increase in transition temperature RT_{NDT}, for materials that closely match RV beltline materials. Aging effects of vessel beltline materials were detected using Charpy V-notch tests and, therefore, the staff concluded the applicant satisfied the criteria for the detection of aging effects as recommended in the GALL Report.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - The applicant stated that monitoring of RV beltline fracture toughness is accomplished through testing of surveillance specimens from surveillance capsules that are periodically withdrawn from the vessels. Trending is accomplished through RG 1.99, Revision 2 methods for projection of RT_{NDT} and USE. Projection of the increase in RT_{NDT} and the decrease in USE provides early indication of the fracture toughness properties of the PBNP RV beltline materials. To date, four surveillance capsules have been removed and tested from each Unit's RV. One of the standby capsules has also been removed from each Unit's RV and is being stored at PBNP. Since the original surveillance capsules did not contain the most limiting material with respect to embrittlement, an additional surveillance capsule was installed in 2002 that contains the most limiting material. Withdrawals of this additional capsule will provide meaningful data for 60 years of operation. In addition, the supplemental capsules are available for testing and alternate dosimetry is not required in conformance with provision seven of GALL AMP XI.M31. Based on this discussion, the staff concluded that the applicant satisfied the criteria for the monitoring and trending as recommended in the GALL Report.

The staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - The applicant, in its clarification letter, dated September 4, 2004, stated that the USE acceptance criteria require that the RV beltline materials must have USE values above 50 ft-lbs until the EOL extension, using the methods of RG 1.99, Revision 2, with the PBNP-specific and integrated surveillance program data as inputs or an equivalent margin analysis must be performed. The RT_{pts} of the most limiting material in the RV beltline must not exceed the PTS screening criteria specified by 10 CFR 50.61, unless it can be demonstrated by alternate means, as allowed by 10 CFR 50.61, that the probability of brittle fracture of the RV in a PTS event is acceptably low.

The acceptance criterion for P-T curves is that the flaw stability criteria of ASME Code Section XI, Appendix G are met for all normal operating conditions as required by

10 CFR Part 50, Appendix G. The acceptance criteria of the ASME Code, Section XI, Appendix G may be modified through application of ASME Code Case N–641, which allows the use of the K_{IC} curve, an alternate fracture toughness curve to the K_{IC} curve.

Additionally, the applicant stated that, if no reasonably practical flux reduction program can be shown to prevent RT_{pts} values from exceeding the PTS screening criteria prior to EOL, other options allowed by 10 CFR 50.61(b) will be evaluated and implemented.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.6. The staff found acceptable the use of fracture toughness curves pursuant to the guidance provided in ASME Code Case N-641. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - The applicant stated that the Units 1 and 2 P-T limits have been developed as required. The applicant also stated that the actuation of low temperature overpressure protection (LTOP) system relief valves at Unit 1 on October 23, 1997 avoided an overpressurization event.

The applicant stated that Unit 1 will continue to satisfy the requirements of 10 CFR Part 50, Appendix G and 10 CFR 50.61 through the end of the period of operation. However, RT_{PTS} for the intermediate-to-lower shell girth weld in the Unit 2 vessel is predicted to exceed the PTS screening criteria prior to the end of license extension. The applicant addressed the issue of RT_{PTS} by discussing several options including flux reduction, advanced analysis and other options. This is further discussed in SER Section 4.2.1.

The applicant modified its surveillance capsule program to incorporate data from the B&W integrated surveillance program. A replacement surveillance capsule containing materials closely matching the limiting materials for both Units 1 and 2 has been installed in the Unit 2 RV during the 2002 refueling outage. The newly installed capsule will be withdrawn during an outage at which it accumulates a fluence equivalent to the 60 calendar year vessel fluence. Data from an integrated surveillance program that includes all PWRs with RVs fabricated by B&W will also be used to predict embrittlement of the RV limiting beltline material.

The staff confirmed in its review of the TLAAs on neutron irradiation embrittlement that the applicant applied all relevant copper and nickel alloy chemistry data to the assessments. These assessments are included in LRA Section 4.2 and are evaluated in SER Section 4.2. The staff concluded that the operating experience program attribute is acceptable since the applicant referred to all of the surveillance data that are applicable to the Reactor Vessel Surveillance Program and the TLAAs on neutron irradiation embrittlement.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

<u>FSAR Supplement</u>. In LRA Section A15.2.18, the applicant provided the FSAR supplement for the Reactor Vessel Surveillance Program. The staff reviewed these sections and determined

that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review, RAI response, and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.18 Steam Generator Integrity Program

Summary of Technical Information in the Application. The applicant's Steam Generator Integrity Program is described in LRA Section B2.1.19, "Steam Generator Integrity Program." In the LRA, the applicant stated that this is an existing program that is consistent, with enhancements, with GALL AMP XI.M19, "Steam Generator Tube Integrity."

The Unit 1 SGs were replaced in 1984 and use thermally treated Alloy 600 SG tubing, stainless steel tube supports and chrome plated Alloy 600 anti-vibration bars. The Unit 2 SGs were replaced in 1997 and use Alloy 690 tubing, stainless steel tube supports and anti-vibration bars.

The Steam Generator Integrity Program incorporates the guidance of NEI 97-06 "Steam Generator Program Guidelines," and maintains the integrity of the SG, including tubes, tube plugs or other tube repairs, and various secondary-side internal components. The program manages aging effects through a balance of prevention, inspection, evaluation, repair, and leakage monitoring measures. Component degradation is mitigated by controlling primary and secondary water chemistry. Eddy current testing is used to detect SG tube degradation and flaws. Visual inspections are performed to identify degradation of various secondary-side SG internal components. A tube integrity assessment is done following each SG tube inspection. The purpose of the assessment is to ensure that the performance criteria have been met for the previous operating period and will continue to be met for the next period. NRC reporting requirements are in accordance with plant technical specifications and NEI 97-06.

Periodic visual inspections of accessible areas are performed to verify the integrity of secondary-side components and to assess tube fouling. The inspections include the upper tube bundle, tube support plates, swirl vane, moisture separator, and feed ring areas.

The Steam Generator Integrity Program is an existing program that is consistent with the GALL Report, Section XI.M19, "Steam Generator Tube Integrity," with regard to managing the aging effects of SG tubes, and tube plugs or other tube repairs. The Steam Generator Integrity Program is also considered an existing plant-specific program that consists of the appropriate 10 elements described in Branch Technical Position RLSB-1, "Aging Management Review-Generic," which is included in Appendix A of NUREG-1800, "Standard Review Plan for

Review of License Renewal Applications for Nuclear Power Plants," for managing the aging effects of various SG secondary-side internal components.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.19, regarding the applicant's demonstration of the Steam Generator Integrity Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

Steam generator aging management incorporates provisions of NEI 97-06. The industry guidelines include an assessment of degradation mechanisms considering the operating experience from similar SGs to identify all potential degradation mechanisms that should be considered during inspection. For each identified mechanism, the industry guidelines define the inspection techniques, measurement uncertainty and the sampling strategies. The industry guidelines provide criteria for the qualification of personnel, specific techniques and the associated acquisition and analysis of data, including procedures, probe selection, analyses protocols and reporting data. Performance criteria are specified and pertain to structural integrity, accident induced leakage and operational leakage. The Steam Generator Integrity Program includes guidance on assessment of degradation mechanisms, inspection, tube integrity, maintenance, repair, leakage monitoring as well as control of water chemistry. Water chemistry control of both primary and secondary water is an integral component outlined in NEI 97-06 and as a method to limit age-related degradation. NEI 97-06 identifies the provision for monitoring secondary-side SG components to ensure that failure of a secondary-side component will not impact the ability of the SG to fulfill its safety-related function.

The staff reviewed the Steam Generator Integrity Program against the AMP elements found in the GALL Report, SRP-LR Section A.1.2.3, and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

LRA Section B2.1.19 states that the Steam Generator Integrity Program is consistent with the GALL Report, with enhancements. The applicant stated that enhancements include plant procedure revisions to specify the inspections of additional secondary-side components, provide acceptance criteria, and improve the inspection documentation. The staff considered this type of enhancement to be an administrative enhancement that does not require staff review.

(1) Scope of the Program - The applicant stated that the scope of the program was structured to meet NEI 97-06 and applicable plant technical specifications. The applicant's discussion of the program scope indicated that the various secondary-side components were included, but did not clearly elaborate on which secondary-side components were included in the program scope. As discussed in SER Section 3.1, the

staff requested the applicant to identify all the components within the secondary-side inspection scope. In a letter, dated January 6, 2005, the applicant stated that aging of the following components would be managed by this portion of the Steam Generator Integrity Program: anti-vibration bars, blowdown piping nozzles and secondary-side shell penetrations, feedwater nozzle, secondary closures, steam outlet nozzle, transition cone girth weld, tube bundle wrapper and wrapper support system, tube support plates, tubesheet and the upper and lower shell, elliptical head and transition cone. The applicant also indicated that portions of the upper tube bundle, tube support plates, swirl vane, moisture separators and feed ring are inspected. The scope adequately addresses those components identified as potentially susceptible to aging degradation. Therefore, the staff found this acceptable.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - The applicant stated that the Water Chemistry Control is in place to mitigate the potential corrosion related degradation of primary and secondary components. The Water Chemistry Control Program is evaluated in SER Section 3.0.3.2.20. In addition, the applicant indicated that the guidelines of NEI 97-06 include foreign material exclusion requirements to limit fretting and wear-related degradation and that sludge lancing is used to minimize the potential for pitting associated with sludge piles. The staff found that the preventive actions identified are acceptable and will assist in managing aging of the components within the program scope.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - The applicant stated that the SG tube inspections are performed in accordance with plant technical specifications and NEI 97-06. Primary to secondary leakage is monitored to verify tube integrity during plant operations and tube integrity is assessed against the NEI 97-06 performance criteria. Secondary-side visual inspections are performed to assess the condition of components within the program scope. The program requires periodic visual inspection of the upper tube bundle, tube support plates, swirl vane, moisture separators and feed ring. A number of the components identified by the applicant as within the program scope have limited visual accessibility. As discussed in SER Section 3.1, the staff requested the applicant to identify how these components will be inspected as part of the secondary-side SG visual inspections (*i.e.*, anti-vibration bars). The applicant stated that for those components with limited visual accessibility, similar material/environment combinations will be relied on to provide indication of the potential for age-related degradation. The staff concluded that the parameters monitored or inspected are acceptable. Inspections are performed in accordance with plant technical specifications; NEI 97-06 criteria and performance of SG secondary inspections would provide meaningful information regarding aging of SG components.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.3. The staff concluded that this program attribute is acceptable.

(4) Detection of Aging Effects - The applicant stated that its program complies with the plant technical specifications and with NEI 97-06 criteria by using the program extent and schedule for inspections to ensure that flaws do not exceed established performance criteria. The applicant indicated that tube integrity assessments account for uncertainties associated with detectability and sizing of certain types of flaws. In addition, the applicant indicated that periodic visual secondary-side SG inspections would provide reasonable assurance that degradation would be detected before a loss of intended function or the integrity of the tubes was challenged. As discussed in SER Section 3.1, the staff requested the applicant to discuss how aging effects would be detected in components with limited access for visual inspection.

In a letter, dated January 6, 2005, the applicant stated that the secondary-side inspections were intended to augment the Water Chemistry Control Program and committed to perform secondary-side visual inspections of accessible areas to verify the integrity of SG secondary-side components at least every six years, with one SG being inspected every three years on an alternating basis. The applicant stated that the Water Chemistry Control Program was intended to mitigate corrosion related degradation in the SG. The secondary-side visual inspections are intended to augment water chemistry and verify its effectiveness by conducting a general condition assessment. The applicant indicated that where the component is inaccessible to visual inspection, the applicant intends to inspect components with a similar material/environment combination to provide insight into the potential for age-related degradation. The applicant's response included a new commitment regarding the frequency of secondary-side visual inspection stating that any indications of degradation or unacceptable conditions will be evaluated through the corrective action program, including extent of condition. The staff concluded that aging effects should be adequately detected by the program. The applicant will use both a mitigating strategy and inspections of accessible components.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in the GALL Report and SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - The applicant stated that inspection intervals based upon the technical specifications and NEI 97-06 are expected to provide timely detection of tube degradation. Primary to secondary leakage is monitored and will identify degradation of SG tubing. In addition the applicant indicated that operational assessments are performed to verify that structural and leakage integrity will be maintained during the operating interval until the next required inspection. The applicant indicated that the results of the secondary-side inspections are documented, evaluated and compared to the results of previous secondary-side inspections in order to monitor on-going degradation. The staff found that the applicant's monitoring and trending is acceptable. Condition monitoring and operational assessments will address potential degradation modes and provide assurance that SG integrity will be met during future operating cycles.

The staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - The applicant stated that the acceptance criteria are in accordance with the plant technical specifications and NEI 97-06. The applicant indicated that any loose part or foreign material that is identified is removed from the SG unless it is shown by evaluation that these items will not cause unacceptable tube damage. The applicant indicated that tube inspections are followed by assessments of tube integrity relative to performance criteria in the areas of structural integrity and operational and accident leakage integrity. The applicant also indicated that when SG tubes do not meet the acceptance criteria, the tubes are repaired or removed from service by plugging. The applicant utilizes primary-to-secondary leakage criteria in accordance with NEI 97-06, which is more restrictive than the technical specification limits.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.6. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - The applicant stated that the Steam Generator Integrity Program has been effective in ensuring timely detection and correction of the aging effects for SGs. The applicant's program incorporates the plant technical specification requirements and the information contained in NEI 97-06. The applicant has replaced the SGs. In Unit 1, the SGs were replaced in 1984 with SGs utilizing thermally treated Alloy 600 tubes. In Unit 2, the SGs were replaced in 1997 with SGs utilizing Alloy 690 tubes. Both units' replacement SGs employ design changes to enhance material performance.

The applicant indicated that the most recent Unit 1 SG inspection results indicated that the SGs are in very good condition with only 10 of 6428 tubes having been plugged (each SG has 3214 tubes). The applicant indicated that four tubes were preventively plugged prior to operation, four tubes were plugged resulting from AVB wear and two tubes were plugged resulting from damage incurred during maintenance activities. The applicant also indicated that no tubes have been plugged as a result of corrosion-related degradation. As discussed in SER Section 3.1, the staff requested the applicant to provide a discussion regarding activities to address outside diameter stress corrosion cracking (ODSCC) identified at the Seabrook plant in thermally treated Alloy 600 tubing as outlined in INs 2002-21 and 2002-21 Supplement 1. The applicant stated that, as a result of industry operating experience, ODSCC was considered as a potential degradation mechanism in the Unit 1 SG degradation assessment. The applicant also included ODSCC as a potential degradation mechanism for the tubing in the Unit 2 SG, but considers the Alloy 690 tubing to be more resistant to this type of degradation.

The applicant indicated that a special analysis was performed on the 2001 inspection results by Westinghouse to look for the potential susceptibility for ODSCC, which may be indicated by drift in the eddy current signal. This analysis was performed on low row tubes (row 8 and below). The applicant indicated that this analysis indicated that there are 98 tubes that are potentially susceptible to ODSCC. Further, the applicant indicated that during the Spring 2004 SG inspection, these 98 tubes were inspected and analyzed with a heightened sensitivity to ODSCC by the analysts. No indications were identified.

The applicant indicated that the most recent Unit 2 inspection results also indicated the SGs are in very good condition with only four of 6998 tubes having been plugged (each SG has 3499 tubes). All four of these tubes have been plugged as a precautionary measure, two tubes were plugged as a result of small volumetric indications at the top of the tubesheet and two tubes were plugged as a result of excessive eddy current noise. The applicant indicated that no tubes have been plugged as a result of corrosion-related degradation.

The applicant indicated that the SG secondary-side inspections to date have revealed no degradation of the swirl vane, moisture separators, feed ring areas, J-tubes, or tube support plates. The staff concluded that the operating experience supports the applicant's conclusion that the Steam Generator Integrity Program provides reasonable assurance that applicable aging effects will be managed during the license renewal period.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in the GALL Report and SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

FSAR Supplement. In LRA Section A15.2.19, the applicant provided the FSAR supplement for the Steam Generator Integrity Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the ten program elements and determined that the AMP is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.19 Structures Monitoring Program

Summary of Technical Information in the Application. The applicant's Structures Monitoring Program is described in LRA Section B2.1.20, "Structures Monitoring Program." The applicant stated that this is an existing program that is consistent, with enhancements, with GALL AMP XI.S5, "Masonry Wall Program," and GALL AMP XI.S6, "Structures Monitoring Program." The applicant further stated that the Structures Monitoring Program is consistent, with exceptions and enhancements, with GALL AMP XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," and GALL AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems."

The applicant stated that the Structures Monitoring Program manages the aging effects associated with steel (including fasteners), concrete (including masonry block and grout), earthen berms, and elastomers. The environments include below-grade and fluid-exposed material, outdoor weather, and indoor air. The program includes all safety-related buildings, structures within the containment, other buildings within the scope of license renewal, crane bridge and trolley structures, and component supports (including high-energy line break [HELB] structures and panels) within the scope of license renewal. The program provides for periodic visual inspections and examination of accessible surfaces of the structures and components and identifies the aging effects that impact the materials of construction.

The applicant also stated that of the various mechanisms for concrete degradation, only cavitation and abrasion of concrete exposed to flowing water are considered to be of sufficient significance to require aging management. However, this program also provides for comprehensive management of other various potential degradation mechanisms for the concrete structures within the scope of this program.

The Bolting Integrity Program credits this program for the inspection of all structural and component support bolting within the scope of license renewal that is not within the scope of the ASME Code Section XI, Subsection IWF Inservice Inspection Program or Systems Monitoring Program. Bolting associated with the supports for electrical cabinets, conduits, and cable trays also is included within the scope of this program. Visual inspections of bolting are performed concurrent with the structure inspection. The visual inspections check for corrosion, cracking, missing or loose fasteners, and coating degradation.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

During the audit, the staff noted that, for the "scope of the program" program element for Structures Monitoring Program, the applicant incorrectly describes the overhead crane locations for cranes. In a letter dated July 12, 2004, the applicant committed to revise, as part of its LRA annual update, the "scope of the program" program element for the Structures Monitoring Program to add more detail specifically describing overhead crane locations. On this basis, the staff found that the scope of the applicant's program is consistent with the GALL AMP XI.M23.

The staff also noted that, for the "scope of the program" program element for the Structures Monitoring Program, the applicant did not include steel edge supports and bracing for masonry walls, as required by GALL AMP XI.S5. The applicant was requested to provide clarification during the audit. In a letter dated July 12, 2004, the applicant committed to revise, as part of its LRA annual update, the "scope of the program" program element for the Structures Monitoring Program to add a description of the steel edge supports and bracing for masonry walls. On this basis, the staff found that the scope of the applicant's program is consistent with the GALL AMP XI.S5.

In LRA Section B2.1.20, the applicant stated that its Structures Monitoring Program is consistent with GALL AMP XI.S7, with exceptions. The Structures Monitoring Program takes exception to the "scope of the program" program element for GALL AMP XI.S7 in that the applicant has not committed to RG 1.127, Revision 1 and does not include the intake crib, intake pipes, or discharge flume within the scope of license renewal.

GALL AMP XI.S7 states that RG 1.127 applies to water-control structures associated with emergency cooling water systems or flood protection of nuclear power plants. The water control structures included in the RG 1.127 program are concrete structures, embankment structures, spillway structures and outlet works, reservoirs, cooling water channels and canals, intake and discharge structures, and safety and performance instrumentation.

As documented in the audit and review report, the applicant stated that its CLB takes an exception to RG 1.127 in that PBNP does not include inspection of the intake crib, intake pipes, or discharge flume as part of its CLB. This exception to the scope is addressed in SER Section 2.4. The staff reviewed the inspection methods applied by the applicant and determined that the inspections performed on the circulating water pumphouse are consistent with RG 1.127.

On the basis of its review of the inspection methods, as documented in audit and review report, the staff concluded that the inspection methods used by the applicant are consistent with RG 1.127 and, therefore, meet the inspection criteria of GALL AMP XI.S7. On this basis, the staff found the exception acceptable.

The Structures Monitoring Program also takes exception to the "parameters monitored or inspected" program element for GALL AMP XI.M23 in that the applicant does not keep records of the number and magnitude of crane lifts that have been made.

GALL AMP XI.M23 states that, for the "parameters monitored or inspected" program element, the program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes. The number and magnitude of lifts made by the crane are also reviewed.

The applicant stated that, although the records of the number and magnitude of lifts that have been made are not kept, the applicant uses the cranes for the functions they were designed to perform, and the cranes are inspected periodically. Crane usage is well within the design capacity and service duty of the cranes. Any lifts in excess of rated crane capacity would be evaluated and documented pursuant to ANSI B30.2.

As documented in the audit and review report, the applicant informed the staff that the crane's service duty would not be exceeded during the period of extended operation. The applicant directed the staff to LRA Section 4.3.13, "Crane Load Cycle Limit." The staff reviewed this section, as it related to crane operation, and determined that the expected number of lifts is significantly less than the design criteria. On this basis, the staff found this exception acceptable.

In LRA Section B2.1.20, the applicant stated that its Structures Monitoring Program is consistent with GALL AMP XI.S5, XI.S6, XI.S7, and XI.M23, with enhancements. The applicant stated that, for the "detection of aging effects" program element, enhancements include revisions to existing implementing documents to perform specific inspections related to aging effects, indicate the parameters to be monitored, and provide acceptance criteria. New implementing procedures will be created and/or existing procedures revised to include those components not presently inspected. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

Operating Experience. The staff reviewed the applicant's operating experience for the Structures Monitoring Program.

The applicant stated that masonry walls are inspected pursuant to plant procedures. Cracks in masonry walls have been found primarily at the mortar joints and these findings have been documented and resolved. Concrete structure inspections have been and continue to be a large part of the Structures Monitoring Program as described in plant procedures. Cracks, erosion, corrosion of embedded steel, and concrete spalling have been observed. These findings are evaluated and resolved by engineering. Periodic inspections of the circulating water pumphouse have been an ongoing program. Divers perform inspections during refueling outages. Minor degradation of these concrete structures has been found and recorded. Zebra mussels are periodically removed from the forebay areas. The structural members of the cranes that are in the scope of this program are inspected. There has been no corrosion-related degradation found on these structure components.

Also, the applicant stated that no signs of physical damage have been observed on the earthen berm around the above-ground fuel oil storage tanks. Industry operating experience has shown that degradation occurs in structural steel and concrete components. The inspections performed at PBNP as part of the Structures Monitoring Program have revealed that degradation has occurred in both concrete and structural steel components. The inspection results are recorded in an annual report. Any degradation determined to be a potential cause of failure or indicative of changing conditions that may lead to an increased degradation rate is documented in the corrective action program.

The applicant performed a review of NRC inspection reports, QA audit/surveillance reports, and self-assessments since 1999. The review revealed no issues or findings that could impact the effectiveness of the Structures Monitoring Program. In the first quarter of 2003 PBNP performed a maintenance rule assessment, which reviewed the structural monitoring portion of the maintenance rule. The assessment concluded that the overall structural monitoring program was acceptable with program enhancements recommended. These enhancements were entered into the corrective action program and resolved. As additional operating experience is obtained, lessons learned may be used to adjust this program.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Structures Monitoring Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.20, the applicant provided the FSAR supplement for the Structures Monitoring Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.20 Water Chemistry Control Program

Summary of Technical Information in the Application. The applicant's Water Chemistry Control Program is described in LRA Section B2.1.24, Water Chemistry Control Program." The applicant stated that this is an existing program that is consistent, with exceptions and enhancements, with GALL AMP XI.M2, "Water Chemistry."

The applicant stated that the objective of the Water Chemistry Control Program is to protect the integrity, reliability, and availability of systems and components by managing the water chemistry in plant systems to ensure that water quality is compatible with the materials of construction and to minimize corrosion of internal surfaces exposed to corrosive environments. The program monitors and controls water chemistry based on the guidelines in EPRI TR-105714, "PWR Primary Water Chemistry Guidelines," for primary water chemistry and EPRI TR-102134, "PWR Secondary Water Chemistry Guidelines," for secondary water chemistry.

The applicant also stated that the One-Time Inspection Program verifies that the Water Chemistry Control Program is managing the effects of aging in low flow or stagnant areas.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In LRA Section B2.1.24, the applicant stated that its Water Chemistry Control Program is consistent with GALL AMP XI.M2, with exceptions. The Water Chemistry Control Program takes exception to the "scope of the program" program element for GALL AMP XI.M2 in that the optimization of primary water chemistry to address individual plant circumstances and the impact of the NEI SG initiative, NEI 97-06, "Steam Generator Program Guidelines," which recommends that utilities meet the intent of the EPRI guidelines. EPRI TR-105714, Revision 4, attempts to clearly distinguish between prescriptive requirements and non-prescriptive guidance.

EPRI TR-102134, Revision 5, provides additional details regarding plant-specific optimization and clarifies which portions of the EPRI guidelines are mandatory under NEI 97-06.

The applicant also stated that a review of NRC inspection reports, QA audit/surveillance reports, and self-assessments since 1999 revealed no issues that could impact the effectiveness of the Water Chemistry Control Program. Additionally, industry experience indicates that using the EPRI guidelines for water chemistry has proven very effective in managing the degradation of primary and secondary SSCs. The EPRI water chemistry guidelines are revised periodically based upon industry experience.

As documented in the audit and review report, the staff reviewed the information and held discussions with the applicant's technical staff. On the basis of its review, the staff determined that the use of EPRI guidelines, EPRI TR-105714, Revision 4, for primary water chemistry and EPRI TR-102134, Revision 5, for secondary water chemistry, is acceptable. As discussed above, these revisions improve the effectiveness of the Water Chemistry Control Program and are expected to ensure proper aging management. Therefore, the staff found this exception acceptable.

The Water Chemistry Control Program also takes exception to the "parameters monitored or inspected" program element for GALL AMP XI.M2 in that (1) EPRI TR-105714, Revision 4, lists pH and conductivity as primary water diagnostic parameters to be monitored during power operation, but does not provide acceptance limits; (2) the applicant does not routinely monitor for lead; (3) PBNP deviates slightly from EPRI TR-102134, Revision 5, in the manner in which the hydrazine concentration is maintained; and (4) EPRI TR-102134, Revision 5, lists pH and conductivity as secondary water diagnostic parameters to be monitored when the RCS temperature is greater than 200 °F, but does not provide acceptance criteria.

GALL AMP XI.M2 states that the water quality (pH and conductivity) is maintained in accordance with the EPRI guidelines. EPRI TR-105714, Revision 4, lists pH and conductivity as primary water diagnostic parameters to be monitored during power operation but does not provide acceptance limits.

As discussed in its evaluation for the "scope of the program" program element, the staff determined that the use of EPRI guidelines, EPRI TR-105714, Revision 4, for primary water chemistry and EPRI TR-102134, Revision 5, for secondary water chemistry, is acceptable.

The applicant stated that during startup conditions with the reactor coolant system at greater than 200 °F but at less than 5 percent reactor power, EPRI requires that hydrazine in the SG feedwater source be maintained at greater than 100 ppb (or greater than eight times the oxygen level, whichever is higher). The applicant does not have the capability for maintaining a continuous hydrazine feed at these conditions. Alternatively, the applicant makes batch additions of hydrazine to SGs through the auxiliary feedwater system to maintain detectable hydrazine levels in the SG blowdown.

The applicant also stated that making batch additions of hydrazine to the SGs through the auxiliary feedwater system to maintain detectable hydrazine levels in the SG blowdown is adequate to ensure that there is little dissolved oxygen in the SG bulk water supply to contribute to corrosive conditions.

As documented in the audit and review report, the staff reviewed information provided by the applicant and held discussions with the applicant's technical staff. On the basis of its review, the staff determines that the proposed bulk addition of hydrazine and the use of EPRI guidelines (EPRI TR-105714, Revision 4, for primary water chemistry, and EPRI TR-102134, Revision 5, for secondary water chemistry) are appropriate. On this basis, the staff found this exception acceptable.

In LRA Section B2.1.24, the applicant stated that its Water Chemistry Control Program is consistent with GALL AMP XI.M2, with enhancements. The applicant stated that, for the "detection of aging effects" and "monitoring and trending" program elements, enhancements include revisions to existing implementing procedures to include the applicable aging effects. Procedures will also be revised to require additional sampling after corrective actions have been taken whenever a parameter is not within the specified value and continuous monitoring is not available. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

Operating Experience. The staff reviewed the applicant's operating experience for the Water Chemistry Control Program.

The applicant stated that its Water Chemistry Control Program has been in effect since initial plant operation and has been effective at maintaining the desired system water chemistry and detecting abnormal conditions, which have been corrected in an expedient manner. The applicant stated that a review of condition reports/action requests supports the above statement as most are related to abnormal chemistry results during operational transients such as startups where the abnormal condition is expected, but the corrective action program is used for documentation.

The EPRI guidelines for water chemistry are being used and the controlling procedures refer and adhere to the limits specified in them. The applicant stated that, over time, this has proven to be an effective method of controlling concentrations of parameters such as sulfates, chlorides, fluorides, dissolved oxygen, lithium, sodium, iron, and copper that are detrimental to certain alloys in both the primary and secondary systems. Controlling these parameters mitigates aging effects in primary and secondary system components.

The applicant also performed a historical review of reactor coolant system data for sulfates as an indicator of a resin intrusion event and did not reveal any evidence of such an event. An assessment performed by PBNP in 2003 concluded that the chemistry program meets expectations. A self-assessment conducted in mid-2003 concluded that the primary and secondary water chemistry programs meet station requirements; however, some process weaknesses exist. These process weaknesses are being tracked via the corrective action program.

In addition, the applicant performed a review of NRC inspection reports, QA audit/surveillance reports, and self-assessments since 1999. The review revealed no other issues or findings that could impact the effectiveness of the Water Chemistry Control Program. Review of plant-specific operating experience also indicates that the chemistry program is performing its function of mitigating aging effects. No reports were found that attributed water chemistry as the cause of component deterioration, showing signs of aging effects, or failing to perform an intended function. Action requests are initiated when water chemistry is found to be out of specification, and most of the instances occur during start-up when parameters are quickly changing and it is more difficult to control water chemistry. The time duration of out-of-specification water chemistry is minimal and there is no evidence of its having caused detrimental effects on system components. As additional operating experience is obtained, lessons learned may be used to adjust this program.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. The staff concluded that the operating experience is consistent with industry practice. In addition, the staff found that the historical review results did not identify resin intrusion. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Water Chemistry Control Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.24, the applicant provided the FSAR supplement for the Water Chemistry Control Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.21 Environmental Qualification Program

Summary of Technical Information in the Application. The applicant's Environmental Qualification Program is described in LRA Section B3.1, "Environmental Qualification Program." The applicant stated that this is an existing program that is consistent, with enhancements, with GALL AMP X.E1, "Environmental Qualification of Electric Components."

The applicant stated that the Environmental Qualification Program manages component thermal, radiation and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. In accordance with 10 CFR 54.21(c)(1)(iii), the Environmental Qualification Program, which implements the requirements of 10 CFR 50.49, is viewed as an AMP for license renewal. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered TLAAs for license renewal. The Environmental Qualification Program ensures that these EQ components are maintained within the bounds of their qualification bases.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report.

In LRA Section B3.1, the applicant stated that its Environmental Qualification Program is consistent with GALL AMP X.E1, with enhancements. The applicant stated that enhancements to its Environmental Qualification Program include completing the EQ backlog elimination project to eliminate the backlog of outstanding EQ related tasks and addressing the recommendations from an independent assessment of the program, which include field verification of EQ components and the completion of EQ checklist reviews. These enhancements are intended to improve the overall health and effectiveness of the Environmental Qualification Program. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

Operating Experience. The staff reviewed the applicant's operating experience for the Environmental Qualification Program.

The applicant stated that although some program execution issues have previously been experienced, a review of plant-specific and industry operating experience identified no premature failures due to aging effects that could affect the qualified life of an EQ component.

The applicant also performed a review of the NRC Inspection reports, QA audit/surveillance reports, and self-assessments since 1999 to determine the effectiveness of its EQ program as it currently exists. The applicant stated that numerous weaknesses were identified from a design and programmatic perspective. These weaknesses are indicative of issues related to executing existing PBNP commitments to 10 CFR 50.49 and do not indicate that changes are needed to the requirements (*i.e.*, scope, qualification methods, acceptance criteria) established by these commitments. The Environmental Qualification Program, as currently committed to 10 CFR 50.49, provides reasonable assurance that the intended functions of EQ components will be maintained through the period of extended operation.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. The staff concluded that the operating experience is consistent with industry practice. In addition, the staff expects that the applicant's corrective actions program will ensure that the program will perform its intended function during the period of extended operation. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Environmental Qualification Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Sections A15.3.2 and A15.4.6, the applicant provided the FSAR supplement for the Environmental Qualification Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with 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). The staff also reviewed the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.22 Fatigue Monitoring Program

Summary of Technical Information in the Application. The applicant's Fatigue Monitoring Program is described in LRA Section B3.2, "Fatigue Monitoring Program." The applicant stated that this is an existing program that is consistent, with enhancements, with GALL AMP X.M1, "Metal Fatigue or Reactor Coolant Pressure Boundary."

The applicant stated that the Fatigue Monitoring Program is a confirmatory program that monitors loading cycles due to thermal and pressure transients and cumulative fatigue usage for ASME Code Class 1 and selected Class 2 components analyzed to Class 1 rules for which a cyclic or fatigue design basis exists. The program provides an analytical basis for confirming that the actual number of cycles does not exceed the number of cycles used in the design analysis, and that the cumulative fatigue usage will be maintained below the allowable limit during the period of extended operation. The impact of the effects of reactor coolant environment on component fatigue life, which is a TLAA, has been evaluated for a sample of critical components, including the seven component locations selected in NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components." The results of these analyses are discussed in LRA Section 4.3. The staff's evaluation of this TLAA is documented in SER Section 4.3. The acceptability of these critical component locations, including the effects of reactor coolant environment, will continue to be confirmed by the Fatigue Monitoring Program.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report.

In LRA Section B3.2, the applicant stated that its Fatigue Monitoring Program is consistent with GALL AMP X.M1, with enhancements. The applicant stated that, for the "detection of aging effects" program element, enhancements to the program include modifying existing plant documents to monitor loading cycles and fatigue usage, including the effects of reactor water environment. The staff considered this type of enhancement to be an administrative enhancement that does not require staff review.

Operating Experience. The staff reviewed the applicant's operating experience for the Fatigue Monitoring Program.

The applicant stated that it documented a comprehensive review of industry issues and service-induced fatigue cracking since the late 1970s for Class 1 and 2 components and how its operating experience to date is addressed in the Fatigue Monitoring Program. The review included industry and plant-specific fatigue cracking operating experience associated with main feedwater piping and nozzle fatigue cracking resulting from thermal stratification cycling during low flow and hot standby conditions (NRC Bulletin 79-13, "Cracking in Feedwater System Piping"), potential for fatigue cracking in normally stagnant piping systems attached to the reactor coolant system (NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems"), and thermal fatigue cracking of pressurizer surge piping (NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification"). The applicant's Fatigue Monitoring Program includes reviews of both industry and plant-specific operating experience regarding fatigue cracking for applicability to PBNP. These ongoing reviews are considered when selecting additional monitored components.

The staff reviewed the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Fatigue Monitoring Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.3.3, the applicant provided the FSAR supplement for the Fatigue Monitoring Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with 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). The staff also reviewed the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.23 Pre-Stressed Concrete Containment Tendon Surveillance Program

Summary of Technical Information in the Application. The applicant's Pre-Stressed Concrete Containment Tendon Surveillance Program is described in LRA Section B3.3, "Pre-Stressed Concrete Containment Tendon Surveillance Program." The applicant stated that this is an existing program that is consistent, with enhancements, with GALL AMP X.S1, "Concrete Containment Tendon Prestress."

The applicant stated that the Pre-Stressed Concrete Containment Tendon Surveillance Program is a confirmatory program that monitors the loss of containment prestressing forces in containment tendons throughout the life of the plant, including the period of extended operation. This program consists of an assessment of the results of the tendon prestressing force measurements performed in accordance with ASME Code Section XI, Subsection IWL. The assessment related to the adequacy of the prestressing forces will consist of the establishment of (1) acceptance criteria and (2) trend lines. The acceptance criteria will normally consist of a predicted lower limit (PLL) and the minimum required prestressing force or value (MRV).

Staff Evaluation. The staff's review of LRA Section B3.3 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 RAIs B3.3-1, B3.3-2, B3.3-3, and B3.3-4, dated January 12, 2005, the staff requested the applicant to provide clarification with respect to the "scope of the program," "preventive actions," and "corrective actions" program elements. The applicant responded to the staff's RAIs in a letter dated January 28, 2005.

During a meeting, on February 15, 2005, both the staff and the applicant agreed that if the Loss of Prelaod TLAA is performed in accordance with 10 CFR 54.21(c)(1)(ii) this AMP is not required. Based on discussions with the staff, in a letter dated March 15, 2005, the applicant withdrew LRA Section B3.3. Deletion of the Pre-Stressed Concrete Containment Tendon Surveillance Program is documented in the LRA annual update, dated February 23, 2005.

The staff found the Pre-Stressed Concrete Containment Tendon Surveillance Program deletion acceptable.

FSAR Supplement. The applicant deleted LRA Section B3.3, Pre-Stressed Concrete Containment Tendon Surveillance Program; therefore, an FSAR supplement, LRA Section A15.3.1, is not required.

Conclusion. Based on discussions between the staff and the applicant, NMC, in a letter dated March 15, 2005, withdrew LRA Section B3.3. Deletion of this AMP is documented in the LRA annual update, dated February 23, 2005. For the reasons discussed above, the staff found this program deletion acceptable.

3.0.3.3 AMPs That Are Not Consistent with or Not Addressed in the GALL Report

In LRA Appendix B, the applicant indicated that the following AMPs were plant-specific:

- Periodic Surveillance and Preventive Maintenance Program (B2.1.15)
- Systems Monitoring Program (B2.1.21)
- Tank Internal Inspection Program (B2.1.22)
- Thimble Tube Inspection Program (B2.1.23)

For AMPs that are not consistent with or not addressed by the GALL Report, the staff performed a complete review of the AMPs to determine if they are adequate to monitor and/or manage aging. The staff's review of these plant-specific AMPs is documented in the following SER sections.

3.0.3.3.1 Periodic Surveillance and Preventive Maintenance Program

Summary of Technical Information. The applicant's Periodic Surveillance and Preventive Maintenance Program is described in LRA Section B2.1.15, "Periodic Surveillance and

Preventive Maintenance Program." The applicant stated that this is an existing plant-specific program. The applicant credits this program for managing the aging effects of certain SSCs within the scope of license renewal. The program provides for inspection, examination, or testing of selected structures and components, including fasteners, for evidence of age-related degradation on a specified frequency based on operating experience or other requirements (*e.g.*, Technical Specification or ASME Code requirements). Additionally, the program provides for replacement of certain components on a specified frequency based on operating experience. The Periodic Surveillance and Preventive Maintenance Program is also used to verify the effectiveness of other AMPs.

In a letter dated July 12, 2004, the applicant provided additional information concerning the function and structure for the Periodic Surveillance and Preventive Maintenance Program.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.15, regarding the applicant's demonstration of the Periodic Surveillance and Preventive Maintenance Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Periodic Surveillance and Preventive Maintenance Program against the AMP elements found in the SRP-LR Section A.1.2.3, and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is provided separately in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of the Program - The applicant stated that the Periodic Surveillance and Preventive Maintenance Program consists of activities that manage the aging effects for components in the following systems and structures: auxiliary feedwater, circulating water, Units 1 and 2 containment building structure, containment ventilation, emergency power, essential ventilation, main and auxiliary steam, non-Class 1 RCS components, plant air, pressurizer, primary auxiliary building structure, residual heat removal, service water, SG, and waste disposal.

    The staff reviewed and confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The proposed scope identifies the specific components for which the program manages aging. On this basis, the staff found that the applicant's proposed program scope is acceptable.

(2) Preventive Actions - The applicant stated that there are no preventive measures associated with the aging effects of concern for license renewal.

    The staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff did not identify the need for preventive actions for this AMP because it is a condition monitoring program. Therefore, the staff found this conclusion acceptable.

(3) Parameters Monitored or Inspected - The applicant stated that the condition of selected structures and components is monitored through inspection, examination, or testing for evidence of age-related degradation on a specified frequency based on operating experience or other requirements (*e.g.*, Technical Specification or ASME Code requirements). Certain components are also replaced on a specified frequency based on operating experience.

The staff confirmed the "parameters monitored or inspected" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.3. The specified examination method is capable of identifying and characterizing the parameter monitored and providing data sufficient to conclude that the associated aging effect is adequately managed. On this basis, the staff found that the program element is acceptable.

(4) Detection of Aging Effects - In LRA Section B2.1.15 and its letter, dated July 12, 2004, the applicant stated that the aging effects of concern are detected by inspection, examination, or testing of selected structures and components. Certain components are also replaced on a specified frequency based on operating experience. The applicant also stated that (1) the parameters that are monitored or inspected are linked to the aging effects that are to be managed, (2) the Periodic Surveillance and Preventive Maintenance Program and the 23 other AMPs that credit the Periodic Surveillance and Preventive Maintenance Program adequately describe the data collection, and (3) the examination methods of this program are capable of detecting the aging effects of concern based on industry or plant operating experience.

The staff reviewed and confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4. The detection of aging effects identifies the specific components for which the program manages aging. On this basis, the staff found that the applicant's program element is acceptable.

(5) Monitoring and Trending - In LRA Section B2.1.15 and its letter dated July 12, 2004, the applicant stated that the Periodic Surveillance and Preventive Maintenance Program inspection, examination, testing, and component replacement activities credited for license renewal are performed on a specified frequency based on operating experience or other requirements (*e.g.*, Technical Specification or ASME Code requirements). The results of these surveillance and preventive maintenance activities are documented, and subject to review and approval.

The staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5. Trending of inspection results will be performed and will enhance the applicant's ability to detect aging effects before there is a loss of intended function. On this basis, the staff found that the applicant's program element is acceptable.

(6) Acceptance Criteria - The applicant stated that the acceptance criteria for inspection, examination, or testing of selected structures and components for evidence of age-related degradation are provided in the surveillance and preventive maintenance

activities credited for license renewal. The acceptance criteria are related to the aging effect(s) of concern and are tailored to each individual inspection, examination, or test considering the aging effect(s) being managed. An action request will be initiated whenever the acceptance criteria are not met. Certain components are also replaced on a given frequency based on operating experience.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria *defined in* SRP-LR Section A.1.2.3.6. *The control function performed by this program,* management controls (*e.g.*, the corrective action program and action requests), are in place in the event that acceptance criteria are not met. On this basis, the staff found that the applicant's program element is acceptable.

(10) Operating Experience - The applicant stated that its Periodic Surveillance and Preventive Maintenance Program has been effective in maintaining the intended functions of long-lived passive SSCs. Surveillance and preventive maintenance activities are effectively managed, with an improving trend noted in internal and external assessments performed over the past several years. Numerous condition reports, action requests, and work orders have been generated and resolved through the implementation of this program. This experience demonstrates the effectiveness of this program to identify and correct age-related degradation prior to a loss of intended function.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.610. The staff reviewed, as documented in the staff's audit and review report, the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. The staff concluded that the operating experience is consistent with the industry practice. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Periodic Surveillance and Preventive Maintenance Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. *In LRA Section A15.2.15, the applicant provided the FSAR supplement for* the Periodic Surveillance and Preventive Maintenance Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, as discussed above, 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.2 Systems Monitoring Program

Summary of Technical Information. The applicant's Systems Monitoring Program is described in LRA Section B2.1.21, "Systems Monitoring Program." The applicant stated that this is an existing plant-specific program with portions of the program that are consistent, with exceptions and enhancements, with GALL AMP XI.M29, " Above Ground Carbon Steel Tanks." The applicant credited this program for managing the aging effects for certain SSCs within the scope of license renewal. The program manages aging effects for normally accessible external surfaces of piping, tanks, and other components and equipment within the scope of license renewal.

The applicant stated that the scope of its Systems Monitoring Program includes visual inspections of the external surfaces of components. The Systems Monitoring Program is credited by Boric Acid Corrosion Program, for the inspection of SSC that do not contain borated water, but may be subject to the degrading effects of borated water leakage. The applicant also stated that its Systems Monitoring Program is also credited by the Bolting Integrity Program, for the inspection of bolting. The Systems Monitoring Program credited the Tank Internal Inspection Program for the inspection of inaccessible portions of the condensate storage tanks external surfaces (*i.e.*, tank bottoms).

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.21, regarding the applicant's demonstration of the Systems Monitoring Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation. Also, during its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. Details of the staff's audit evaluation are documented in the staff's audit and review report. Furthermore, the staff reviewed the exceptions and associated justifications to determine whether the AMP, with the exceptions, remains adequate to manage the aging effects for which it is credited.

In LRA Section B2.0, "Aging Management Correlation," the applicant did not identify this AMP as a plant-specific AMP. However, in the discussion of the Systems Monitoring Program, the applicant stated that the System Monitoring Program is an existing plant-specific program. Further, the applicant stated that, since this program includes visual inspection of the external surfaces of carbon steel tanks, it is also an existing program that is consistent with, but includes exceptions to, GALL AMP XI.M29, "Above Ground Carbon Steel Tanks."

The staff reviewed the Systems Monitoring Program against the AMP elements found in the SRP-LR Section A.1.2.3, and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience). The staff also reviewed the consistency of this AMP with GALL AMP XI.M29, which is integrated into the plant-specific evaluations.

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of the Program - The applicant stated that for this program element, the Systems Monitoring Program consists of activities that manage the aging effects for components in the following systems and structures: auxiliary feedwater, chemical and volume control, circulating water, component cooling water, containment hydrogen detectors and recombiners, containment isolation components, containment spray, containment ventilation, emergency power, essential ventilation, feedwater and condensate, fire protection, heating steam, main and auxiliary steam, non-class 1 RCS components, plant air, residual heat removal, safety injection, service water, spent fuel cooling, treated water, and waste disposal.

The applicant also stated that its Systems Monitoring Program takes exceptions to the "scope of the program" program element for GALL AMP XI.M29 in that it does not take credit for any coating or paint for mitigating corrosion even though the tanks may be painted or coated. GALL AMP XI.M29 recommends preventive measures to mitigate corrosion by protecting the external surfaces of above-ground carbon steel tanks with paint or coatings. The applicant stated that inspections of the coating or paint will provide an indication of the condition of the material underneath the coating or paint.

As documented in the audit and review report, the staff reviewed the information and held discussions with the applicant's technical staff. The staff found that surface corrosion would not occur without affecting the coating or paint and such surface degradation would be readily observable. On this basis, the staff found this exception acceptable.

The staff reviewed and confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The proposed scope identifies the specific components for which the program manages aging. On this basis, the staff found that the applicant's proposed program element is acceptable.

(2) Preventive Actions - The applicant stated that there are no preventive measures associated with the aging effects of concern for license renewal.

The applicant also stated that its Systems Monitoring Program takes exception to the "preventive actions" program element for GALL AMP XI.M29 in that (1) it does not take credit for any coating or paint for mitigating corrosion even though the tanks may be painted or coated and (2) sealant or caulking is not used at the interface edge between the tank and the concrete foundation for the condensate storage tanks and above-ground fuel oil storage tanks.

GALL AMP XI.M29 recommends that sealant or caulking be used at the interface edge. The applicant stated that the internals of the above-ground fuel oil storage tanks were inspected in 2000 and no significant rust deposits, corrosion, or other obvious defects were found. Thickness measurements of the bottom of the tanks were performed and indicated no significant loss of material. Subsequent to the inspection and thickness measurements, the tanks were upgraded. The upgrade installed a polyester resin coating on the inside of the tanks, covering the bottoms and extending approximately two feet up the tank walls. The applicant considered that future thickness measurements are not necessary or practical, because of potential thickness measurement complications due to the polyester resin coating, and the absence of any significant material loss due to corrosion in over 30 years of service. This program credits the Tank Internal Inspection Program for thickness measurements of the inaccessible portions of the condensate storage tanks external surfaces (*i.e.*, tank bottoms).

As documented in the audit and review report, the staff reviewed the information and held discussions with the applicant's technical staff. The staff found that (1) surface corrosion would not occur without affecting the coating or paint and such surface degradation would be expected to be readily observable and (2) that the applicant added additional protection barriers to mitigate any future material loss on the above-ground fuel oil storage tanks. On this basis, the staff found these exceptions acceptable.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff did not identify the need for preventive actions for this AMP because it is a condition monitoring program.

(3) Parameters Monitored or Inspected - The applicant stated that the program utilizes periodic plant system walkdowns to monitor for leakage and evidence of material degradation. Above-ground carbon steel tank external coatings or paint are inspected to provide an indication of the condition of the material underneath the coating or paint. Sealants or caulking at the tank/support structure interface, if used to prevent water intrusion, are also inspected for degradation.

The staff confirmed the "parameters monitored or inspected" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.3. The Systems Monitoring Program examination method is capable of identifying and characterizing the parameter monitored and providing data sufficient to conclude that the associated aging effect is adequately managed. On this basis, the staff found that this program element is acceptable.

(4) Detection of Aging Effects - The applicant stated that the external surfaces of various component types (*e.g.*, pump casings, valve bodies, piping, expansion joints) are visually inspected for leakage and evidence of material degradation, such as loss of material due to corrosion. The outer surfaces of above-ground carbon steel tanks are visually inspected for signs of coating or paint degradation to provide an indication of the condition of the material underneath the coating or paint. The sealant or caulking at the tank/support structure interface, if used to prevent water intrusion, is also inspected for degradation. This program credits the Tank Internal Inspection Program for the inspection of inaccessible external surfaces of the Condensate Storage Tanks (*i.e.*, tank bottoms). Degradation of bolted connections is detected by visual inspections of the bolted components during system walkdowns. Bolted connections are inspected for missing fasteners and degradation such as damaged threads and evidence of corrosion.

The applicant also stated that its Systems Monitoring Program takes exception to the "detection of aging effects" program element for GALL AMP XI.M29 in that thickness measurements of the inaccessible external surfaces (*i.e.*, tank bottoms) of the above-ground fuel oil storage tanks are not performed. As discussed with respect to the "preventive actions" program element, this tank was inspected and upgraded in 2000. The inspection did not detect any significant material loss after 33 years of service and the new internal coating provides additional barrier protection.

As documented in the audit and review report, the staff reviewed the information and held discussions with the applicant's technical staff. The staff found that the applicant provided additional protection barriers to mitigate any future material loss on the above-ground fuel oil storage tanks. On this basis, the staff found these exceptions acceptable.

In LRA Section B2.1.21, the applicant stated that the Systems Monitoring Program is consistent with GALL AMP XI.M29, with enhancements. The applicant stated that, for the "detection of aging effects" program element, enhancements include revisions to existing implementing documents to strengthen the requirements for system walkdowns, documentation and records retention, and provide inspection guidance. Additionally, the aging effects and mechanisms to be managed will be incorporated into the existing implementing documents. The staff considered these types of enhancements to be administrative enhancements that do not require staff review.

The staff reviewed and confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4. The System Monitoring Program identifies the specific components for which the program manages aging. On this basis, the staff found that the applicant's program element is acceptable.

(5) Monitoring and Trending - As modified by letter dated February 3, 2005, the applicant stated that visual inspections are performed at least once per operating cycle within the limits of accessibility. The inspection frequency may be increased based on the safety significance, production significance, and operating experience of each system. These system walkdown inspections provide for timely detection of aging effects (*i.e.*, prior to a loss of intended function). Walkdown results are also documented to provide a historical record of items monitored during the walkdowns. This program credits the Tank Internal Inspection Program for the inspection of inaccessible portions of carbon steel tank external surfaces, such as tank bottoms.

The applicant also stated that its Systems Monitoring Program takes exception to the "monitoring and trending" program element for GALL AMP XI.M29 in that thickness measurements of the inaccessible external surfaces of the above-ground fuel oil storage tanks are not performed. This exception is evaluated in the "detection of aging effects" program element, as discussed above. For the reasons discussed above, the staff found this exception acceptable.

The staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5. Detail of the staff's evaluation is documented in its audit and review report. Monitoring of inspection results will be performed and will enhance the applicant's ability to detect aging effects before there is a loss of intended function. On this basis, the staff found that the applicant's program element is acceptable.

(6) Acceptance Criteria - The applicant stated that an action request (which provides a means to document the finding and enter the concern into the plant's corrective action program) will be initiated for any discrepancies found that may affect the component's ability to perform its intended function (*i.e.*, significant degradation). Other types of degradation are recorded for further evaluation. When bolted joints for pressure-retaining components are observed to have significant degradation or be leaking, corrective actions are taken in accordance with the corrective action program. An action request is also initiated for significant degradation of tank coatings or paint, and sealants or caulking (if applicable). Significant degradation consists of cracking, flaking, or peeling of paint or coatings, and cracked sealant or caulking (if applicable). This program credits the Tank Internal Inspection Program for thickness measurements of inaccessible portions of carbon steel tank external surfaces, such as tank bottoms. Thickness measurements will be evaluated against the design thickness.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6. Details of the staff's evaluation are documented in its audit and review report. The staff concluded that evaluating thickness against its design criteria and implementation of the corrective action program is expected to ensure appropriate aging management. On this basis, the staff found that the applicant's program element is acceptable.

(10) Operating Experience - The applicant stated that degradation of components that are within the scope of this program has been documented in accordance with plant procedures in the engineer's system handbooks. This includes inspections of bolting and the external surfaces of tanks. A review of documentation for seven systems within the scope of license renewal indicated that these walkdowns usually result in the initiation of corrective Work Orders for the repair of minor leaks from both flanged connections and valve stem packing, degraded grout under pumps, or pipe supports. Thickness measurements of the bottoms of the above-ground fuel oil storage tanks were performed in August of 2000, which indicated no significant loss of material due to corrosion in over 30 years of service. A review of NRC inspection reports, QA audit/surveillance reports, and self-assessments since 1999 revealed no issues or findings that could impact the effectiveness of the Systems Monitoring Program.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.610. The staff reviewed, as documented in the staff's audit and review report, the operating experience provided in the LRA and interviewed the applicant's technical staff to verify that the plant-specific operating experience did not reveal any degradation not bounded by industry experience. On the basis of its review of the above industry and plant-specific operating experience, the staff concluded that the Systems Monitoring Program will adequately manage the aging effects that are identified in the LRA for which this AMP is credited.

FSAR Supplement. In LRA Section A15.2.21, the applicant provided the FSAR supplement for the system monitoring program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements 10 CFR 54.21(d).

Conclusion. On the basis of its review and audit of the applicant's program, the staff found that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the GALL Report. In addition, the staff reviewed the exceptions and the associated justifications and determined that the AMP, with the exceptions, is adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.3 Tank Internal Inspection Program

Summary of Technical Information in the Application. The applicant's Tank Internal Inspection Program is described in LRA Section B2.1.22, "Tank Internal Inspection Program." In the LRA, the applicant stated that this is a new, plant-specific program.

The Tank Internal Inspection Program manages aging effects on (1) internal surfaces of carbon steel tanks, and (2) inaccessible external surfaces of carbon steel tanks (*i.e.*, tank bottoms) in the auxiliary feedwater and emergency power systems. This program is credited by the Systems Monitoring Program for thickness measurements of the bottom of carbon steel tanks that are sitting directly on the ground or other structures such that external inspection of all surfaces is not possible.

This program provides for periodic inspections to confirm that aging effects will not impair tank intended functions. Tank wall thinning of internal surfaces may be detected by direct visual inspection from inside the tank or indirectly by UT wall thickness measurements from outside the tank. Tank wall thinning of external surfaces that are inaccessible will be detected by UT wall thickness measurements from inside the tank.

This new program is scheduled for implementation prior to the period of extended operation. The applicant does not claim that this program is consistent with the GALL Report.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.22, regarding the applicant's demonstration of the Tank Internal Inspection Program to ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Tank Internal Inspection Program against the AMP elements found in the SRP-LR, Appendix A, Section A.1.2.3, and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of the Program - The applicant stated that the Tank Internal Inspection Program consists of plant-specific activities that manage the aging effect for components in the auxiliary feedwater and emergency power systems. The applicant credits the program for managing the aging effect loss of material due to corrosion on the internal and inaccessible external surfaces (*i.e.*, tank bottoms) of carbon steel tanks.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - The applicant stated that this is an inspection program and as such there are no credited preventive actions. The applicant indicated that some tanks may have internal coatings that aid in preventing loss of material and corrosion. However, the applicant does not credit the coatings for prevention of corrosion within the applicant's program. The applicant stated the coatings will be used as an indicator of substrate condition during visual inspection when available. The staff agrees that the Tank Internal Inspection Program does not include preventive actions and that coatings may be used as an indicator of substrate condition.

The staff confirmed that the "preventive actions" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.2. The staff concluded that this program attribute is acceptable.

(3) Parameters Monitored or Inspected - The applicant stated that the internal surfaces of carbon steel tanks will be periodically visually inspected for the existence of corrosion. Also, the applicant will perform UT thickness measurements to inspect inaccessible external surfaces of carbon steel tanks (*i.e.*, tank bottoms) and may be used from outside on portions of tanks inaccessible for internal visual inspection to detect wall thinning due to corrosion. As discussed below, with regard to the "detection of aging effects" program elements, the staff requested the applicant to provide additional information regarding the extent of the visual inspection and the UT inspections that will be performed for this program. The applicant responded by indicating that visual inspection of the condensate storage tank (CST) will consist of 100 percent of the internal tank surface. The UT inspections of the tank bottom will sample a representative area of the bottom using a grid system. Engineering judgment and previous sample results will be employed by the applicant to establish the grid size. The applicant stated that if degradation is identified, the grid sample size will be reduced to determine the extent of degradation. The staff concluded that the program will adequately monitor for internal tank age-related degradation, a 100 percent internal visual surface inspection of the CST and UT thickness measurements of the tank

bottom will be performed. The staff agrees that visual inspection and UT thickness measurements are capable of detecting degradation potentially affecting tank internals.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3. The staff concluded that the program will adequately monitor age-related degradation and, therefore, is acceptable.

(4) Detection of Aging Effects - The applicant stated that loss of material caused by corrosion will be determined by periodic visual inspection and UT inspection of components within the program scope. Visual inspection will utilize signs of loss of material resulting from degraded coatings, discoloration, pitting and other signs of corrosion. UT inspection will detect loss of wall thickness for tank bottoms and external portions of tanks when the external surfaces are inaccessible for visual inspection. Where visual inspection indicates a loss of material, UT may be used to assess the wall thickness to determine the extent of corrosion. The applicant indicated that the inspection frequency will be based upon operating experience and the results of previous inspections. The applicant indicated that corrective action will be taken whenever acceptance criteria are not met or significant degradation of carbon steel internal tank coating is identified.

The staff's review of LRA Section B2.1.22 identified an area 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.

RAI B2.1.22-1. In RAI B2.1.22-1, dated November 18, 2004, the staff requested the applicant to provide additional information relative to the periodicity of inspection, the inspection scope and bases for the inspection strategies. In its response, dated January 6, 2005, the applicant stated that 100 percent internal surface visual inspection of the condensate storage tanks is conducted at four- to five-year intervals. The applicant indicated that UT inspection of the tank bottom will be conducted on a representative sample of the tank bottom using a grid pattern. The grid size will be based upon engineering judgment. If degradation is identified, a smaller grid will be employed, as well as additional UT measurements to determine the extent of degradation. UT inspection of the tank bottom will be conducted prior to the period of extended operation. Periodic additional UT inspection of the tank bottom will be conducted based upon the results of the initial UT inspection. The DG starting air receivers are inspected at three-year intervals using a combination of internal visual and external UT inspection. Inspections conducted in 2002 and 2003 revealed no adverse conditions.

The staff concluded that the applicant's response is acceptable. The tanks are currently inspected on an established periodicity that is expected to manage aging resulting from loss of material prior to loss of the component's function. The staff also concluded that the applicant's inspections of the condensate storage tank bottoms prior to the period of extended operation is acceptable. This inspection is expected to provide reasonable assurance that potential age-related degradation of the tank bottom will be identified prior to the period of extended operation. The inspection results will be utilized to determine future inspection periodicity. The staff's concern described in RAI B2.1.22-1 is resolved.

For the reasons discussed above, the staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4. The staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - The applicant stated that monitoring and trending will occur if loss of material is detected.

The staff's review of LRA Section B2.1.22, 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 RAIs as discussed below.

RAI B2.1.22-2. In RAI B2.1.22-2, dated November 18, 2004, the staff requested the applicant to provide additional information relative to when monitoring and trending would occur and how accurate rates of degradation would be determined.

RAI B2.1.22-3. In RAI B2.1.22-3, dated November 18, 2004, the staff requested the applicant to explain what is considered as "significant" material loss (as identified in detection of aging effects).

In its response, dated January 6, 2005, the applicant stated that significant coating degradation was considered to exist when the bare substrate was exposed as a result of the degraded coating, and that significant material loss requiring trending is considered to exist when a detectable reduction in the wall thickness exists.

The staff concluded the applicant's response is acceptable. The applicant is expected to commence trending whenever a detectable reduction in wall thickness is identified that is expected to support accurate assessment of aging. The staff's concerns described in RAIs B2.1.22-2 and B2.1.22-3 are resolved.

For the reasons discussed above, the staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5. The staff concluded that this program attribute is acceptable.

(6) Acceptance Criteria - The applicant stated that any degradation of the carbon steel tank internal surfaces will be recorded and evaluated to ensure minimum wall thickness is maintained until the next scheduled inspection. The applicant also indicated that thickness measurements of inaccessible tank bottoms will be evaluated against design thickness values.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6. If degradation is identified, the program's evaluation will attempt to ensure that minimum or design thickness values will not be exceeded in the operating interval prior to the next inspection. The staff concluded that this program attribute is acceptable.

(10) Operating Experience - The applicant stated that in January, 2000, a visual inspection of the south condensate storage tank was conducted. The applicant's inspection identified minor surface rust on the floor of the tank and signs of corrosion through the tank coating on the lower 6 to 8 inches of the tank wall. The applicant documented the

observation in a condition report and evaluated the condition of the tank and coating. The applicant stated that the north condensate storage tank was also inspected as a result of the conditions identified in the south condensate storage tank. The inspection of the north condensate storage tank revealed minor surface rust, similar to that found in the other tank. An engineering evaluation was performed by the applicant on both tanks; the tanks were cleaned and returned to service.

The applicant indicated that the emergency diesel generator starting air receivers, G01 and G02 pressure vessels, are periodically inspected in accordance with Wisconsin Administrative Code requirements. The applicant used visual inspection and UT thickness measurements to inspect the starting air receivers in 2002 and 2003 and found no adverse conditions.

The staff's review of LRA Section B2.1.22, identified an area 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.

RAI B2.1.22-4. Based on related operating experience, tank internal inspections of the north and south condensate tanks have occurred. In RAI B2.1.22-4, dated November 18, 2004, the staff requested the applicant to clarify if these inspections included UT of the tank bottoms. In its response, dated January 6, 2005, the applicant stated that the referenced inspections did not include UT of the tank bottoms. The applicant also stated that, upon implementation of the Tank Internal Inspection Program AMP, condensate tank inspections will include UT of the tank bottoms as a means to monitor any significant corrosion. The applicant indicated that the latest inspection occurred in 2002.

The staff concluded that the applicant's related operating experience is acceptable. It illustrates that the applicant recently completed inspections of components within the program. The operating experience illustrated that, where conditions indicated a potential loss of material, evaluations were performed to assess the tank condition and the inspection scope was expanded to similar components. The staff's concern described in RAI B2.1.22-4 is resolved.

For the reasons discussed above, the staff confirmed that the "operating experience" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.10. The staff concluded that this program attribute is acceptable.

FSAR Supplement. In LRA Section A15.2.22, the applicant provided the FSAR supplement for the Tank Internal Inspection Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review, the RAI responses discussed above, and its audit of the applicant's program, the staff found the AMP exceptions and the associated justifications, are adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.4 Thimble Tube Inspection Program

Summary of Technical Information in the Application. The applicant's Thimble Tube Inspection Program is described in LRA Section B2.1.23, "Thimble Tube Inspection Program." In the LRA, the applicant stated that this is an existing, plant-specific program.

The staff's regulatory basis for establishment of the applicant's Thimble Tube Inspection Program is given in NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors," dated July 26, 1988, which was addressed to all holders of operating licenses or construction permits for nuclear reactors designed by Westinghouse that utilize bottom-mounted instrumentation. In this Bulletin, the staff requested that the addressees establish a Thimble Tube Inspection Program with the following attributes:

- Establish, with technical justification, an appropriate thimble tube wear acceptance criterion (*e.g.*, percent through-wall loss). The staff recommended that the acceptance criterion should include allowances for such items as inspection methodology and wear scar geometry uncertainties.
- Establish, with technical justification, an appropriate inspection frequency.
- Establish an inspection methodology that is capable of adequately detecting wear of the thimble tubes, such as eddy current testing (ECT).

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in LRA Section B2.1.23 regarding the applicant's demonstration that the Thimble Tube Inspection Program will ensure that the effects of aging, as discussed above, will be adequately managed so that the intended functions will be maintained consistent with the CLB throughout the period of extended operation.

The staff reviewed the Thimble Tube Inspection Program against the AMP elements found in the SRP-LR, Appendix A, Section A.1.2.3 and SRP-LR Table A.1-1 and focused on how the program manages aging effects through the effective incorporation of 10 elements (*i.e.*, program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience).

The applicant indicated that the corrective actions, confirmation process, and administrative controls are part of the site-controlled quality assurance program. The staff's evaluation of the quality assurance program is discussed in SER Section 3.0.4. The remaining seven elements are discussed below.

(1) Scope of the Program - The applicant stated that the program will include flux map thimble tubes for both units. The program utilizes ECT to determine thimble tube wall thickness and predict wear rates for the early identification of potential thimble tube failures. All of the thimble tubes on both units will be periodically inspected. The

applicant confirmed that it will continue to perform 100 percent inspection and the inspection frequency will be based on the wear rates.

The staff's review of LRA Section B2.1.23 identified an area 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.

RAI B2.1.23-1. In RAI B2.1.23-1, dated November 17, 2004, the staff requested the applicant to explain the determination of wear rates and the impacts of uncertainties.

In its response, dated January 25, 2005, the applicant stated that to ensure that tube failure does not occur between inspections, tubes predicted to exhibit a wall loss in excess of 60 percent before the next inspection will be capped and taken out of service. The 60 percent criterion is based on maximum allowable wall loss of 83 percent, a 10 percent error in ECT, and a 10 percent uncertainty in wall loss geometry. The staff concluded that the applicant's approach to inspection frequency is acceptable. The staff found that the applicant implements conservative measures and appropriate corrective actions, therefore, the staff's concern described in RAI B2.1.23-1 is resolved.

The staff confirmed that the "scope of the program" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.1. The staff concluded that this program attribute is acceptable.

(2) Preventive Actions - The applicant stated that the evaluation of the remaining thimble tube wall thicknesses, obtained from the ECT, will be used to predict the remaining life of the thimble tubes and to take corrective action before the failure occurs. The staff determined that the Thimble Tube Inspection Program is an inspection-based condition monitoring program and that, as such, does not include preventive or mitigative actions to preclude the occurrence of an aging effect.

(3) Parameters Monitored or Inspected - The applicant stated that wall thickness will be monitored using ECT through periodic inspections

The staff confirmed that the "parameters monitored or inspected" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.3. Since ECT is a standard NDE technique that is appropriate for the detection of wear, the staff concluded that the applicant's program attribute is acceptable.

(4) Detection of Aging Effects - The applicant stated that wear is detected by periodic ECT of the thimble tubes. One hundred percent of the thimble tubes are examined in each thimble tube inspection cycle. The data will be evaluated and remaining wall thickness will be calculated along with the remaining years of life expectancy. In addition, the next inspection cycle will be determined and will take place prior to expiration of calculated expected life. The applicant stated that this will ensure that no leaks occur due to wear of a thimble tube. The applicant will be using ECT inspection methods and, therefore, will detect any aging effects on the thimble tubes. The applicant also confirmed, in response to RAI B2.1.23-1 above, that inspections will normally be performed during the outage prior to the outage identified with the lowest minimum thimble tube life calculation, or at least every six years, to ensure conservative testing intervals. For

example, if the lowest minimum thimble tube life is 5.5 years, the next inspection would be at 3 years, one outage prior to the 4.5 year outage.

The staff confirmed that the "detection of aging effects" program element satisfies the criterion defined in SRP-LR Section A.1.2.3.4. The process adequately provides a method of identifying aging effects and the time to act accordingly. Therefore, the staff concluded that this program attribute is acceptable.

(5) Monitoring and Trending - The applicant stated that the ECT results will be trended and wear rates will be calculated. The wear rate is calculated by considering the total wall loss over the life of the thimble tube divided by the operating time of the tube. The frequency of inspection is based on the maximum wall loss noted in a region of active fretting and the projected wear that would occur based on a known wear rate. The wear rate is determined for each thimble tube and wear location (*i.e.*, thimble tubes may have fretting wear at multiple locations).

The staff confirmed that the "monitoring and trending" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.5. Based on the above described monitoring and trending plan, the staff concluded that the program attribute is conservative and failures of the tubes will be prevented prior to a leak occurring. The staff, therefore, concluded that this program attribute is acceptable.

(6) Acceptance Criteria - The applicant stated that the thimble tubes will be capped if their indicated wall loss plus the predicted wall loss before the next inspection exceeds 60 percent. This is a conservative criterion, since calculations have shown that a tube would have to wear 83 percent of wall tube thickness prior to failing and causing a leak. The 83 percent loss of wall tube failure determination was also conservatively calculated, since it assumes even wear around the tube although wear is a localized degradation mode. As discussed in RAI B2.1.23-1, the applicant stated that the 60 percent criterion includes consideration of error in ECT inspection and uncertainty in wall loss geometry. In addition, the applicant's inspection will normally be performed during the outage prior to the outage that would be identified with the lowest minimum thimble tube life calculation, or at least every six years, to ensure conservative testing intervals.

The staff confirmed that the "acceptance criteria" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.6. Based on the above discussion, the staff concluded that the applicant provided an appropriate wall loss acceptance criteria. The staff, therefore, concluded that this program attribute is acceptable.

(10) Operating Experience - The applicant stated that thimble tubes were replaced in 1985 for Unit 1 and in 1984 for Unit 2 due to internal blockages. No leaking in core thimble tubes was discovered during the first 13 years of operation. The replacement tubes are made of Type 316 stainless steel with a nominal outside diameter of 0.313 inches and a nominal inside diameter of 0.21 inches.

The Thimble Tube Inspection Program was initiated in response to NRC Bulletin 88-09. As a result of inspections performed by the program, five tubes on Unit 1 have been replaced, due to wear, since 1985. One of these five tubes had been capped, one other showed significant wear and three others were replaced because they showed the most wear of the remaining tubes. These last three tubes were not at minimum wall thickness nor did any calculations indicate that they would be at a minimum wall thickness before the next inspection.

In the LRA, the applicant discussed several concerns related to inspection deferrals, calculation methodology, and record retention. As discussed above with respect to the resolution of RAI B2.1.23-1, the applicant stated the following:

- In the past it has deferred the thimble tube inspections for both units. However, in no case did the inspection interval exceed the lowest minimum thimble tube life on either unit. These deferrals were without a documented evaluation showing that there would be no problems with the extended inspection interval. The current implementing document requires an engineering evaluation or calculation to be performed, demonstrating with a high degree of confidence that there would be no thimble tube problems with an extended inspection interval prior to deferral being allowed.

- Following the Unit 2 thimble tube inspection performed during the 2000 refueling outage, it was discovered that the ECT contractor had reported the results using an averaged flaw depth method (*i.e.*, mixed frequency and amplitude wall loss) instead of the worst case flaw depth method (*i.e.*, maximum wall loss). The results were subsequently reanalyzed using the worst case flaw depth method. It was also discovered that the worst case flaw depth method has been largely replaced in the industry with the mixed frequency amplitude wall loss method. Future inspections may be analyzed using both of these methods to determine if PBNP should change to the current industry standard method.

- The concern expressed in the LRA regarding record retention involved copies of the official records maintained by the Thimble Tube Condition Assessment Engineer for ease of reference. The previous Thimble Tube Condition Assessment Program Engineer had disposed of these working copies, since they were redundant to the official records being maintained. However, in all cases, the official records were retained and stored appropriately.

By letter, dated July 19, 2005, the applicant informed the staff that two inspections have occurred in 2004 and 2005. Based on a review of those results, NMC concluded that the current industry method is appropriate; therefore, NMC is adopting the current industry standard of the mixed frequency amplitude wall loss data analysis method to begin during the PBNP fall 2005 Unit 1 refueling outage. The staff found this acceptable, as both methods (average flaw depth and worse case flaw depth) were previously found satisfactory.

The staff confirmed that the "operating experience" program element satisfies the criteria defined in SRP-LR Section A.1.2.3.10. The applicant demonstrated operating experience of no leakage due to failure of thimble tubes. Moreover, the process of inspection deferral, calculation methodology, and record retention have been appropriately addressed. The staff concluded that this program attribute is acceptable.

FSAR Supplement. In LRA Section A15.2.23, the applicant provided the FSAR supplement for the Thimble Tube Inspection Program. The staff reviewed these sections and determined that the information in the FSAR supplement provides an adequate summary of the program activities. The staff found these sections of the FSAR supplement meet the requirements of 10 CFR 54.21(d).

Conclusion. On the basis of its review, the RAI response discussed above, and its audit of the applicant's program, the staff found that the AMP exceptions and the associated justifications are adequate to manage the aging effects for which it is credited. 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 the FSAR supplement for this AMP and found that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.4 Quality Assurance Program Attributes Integral to Aging Management Programs

Pursuant to 10 CFR 54.21(a)(3), a license renewal applicant is required to demonstrate that the effects of aging on SCs subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. NUREG-1800, Branch Technical Position RLSB-1, "Aging Management Review - Generic," describes ten attributes of an acceptable AMP. Three of these ten attributes are associated with the QA activities of corrective action, confirmation process, and administrative control. Branch Technical Position RLSB-1 Table A.1-1, "Elements of an Aging Management Program for License Renewal," provides the following description of these quality attributes:

- corrective actions, including root cause determination and prevention of recurrence, should be timely;
- the confirmation process should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective; and
- administrative controls should provide a formal review and approval process.

NUREG-1800, Branch Technical Position IQMB-1, "Quality Assurance For Aging Management Programs," noted that those aspects of the AMP that affect quality of safety-related SSCs are subject to the QA requirements of 10 CFR Part 50, Appendix B. Additionally, for nonsafety-related SCs subject to an AMR, the existing 10 CFR Part 50, Appendix B, QA program may be used by the applicant to address the elements of corrective action, confirmation process, and administrative control. Branch Technical Position IQMB-1 provides the following guidance with regard to the QA attributes of AMPs:

- Safety-related SCs are subject to 10 CFR Part 50, Appendix B, requirements which are adequate to address all quality-related aspects of an AMP consistent with the CLB of the facility for the period of extended operation.
- For nonsafety-related SCs that are subject to an AMR, an applicant has an option to expand the scope of its 10 CFR Part 50, Appendix B, program to include these SCs to address corrective action, confirmation process, and administrative control for aging management during the period of extended operation. In this case, the applicant should

document such commitment in the FSAR supplement in accordance with 10 CFR 54.21(d).

3.0.4.1 Summary of Technical Information

LRA Section 3.0 provides an AMR summary for each unique structure, component, or commodity group at Units 1 and 2 determined to require aging management during the period of extended operation. This summary includes identification of aging effects requiring management and AMPs utilized to manage these aging effects. LRA Appendices A and B demonstrate how the identified programs manage aging effects using attributes consistent with the industry and NRC guidance. In LRA Section A15.1, the applicant stated that the QA program includes the elements of corrective action, confirmation process, and administrative controls and is applied to both safety-related and nonsafety-related SSCs that are within the scope of license renewal. In LRA Section B1.3, the applicant discusses the implementation of 10 CFR Part 50, Appendix B, and its consistency with the summary in NUREG-1800 Appendix A.2 (Reference B-1). The QA Program includes the elements of corrective action, confirmation process, and administrative control, and is applicable to the safety-related and nonsafety-related SSCs that are subject to an AMR. In many cases, existing programs were found to be adequate for managing aging effects during the period of extended operation. Generically the three elements are applicable as follows:

<u>Corrective Action</u>. A single corrective action process is applied regardless of the safety classification of the structure or component. Corrective actions are implemented through the initiation of an action request in accordance with plant procedures established pursuant to 10 CFR Part 50, Appendix B. Plant procedures require the initiation of an action request for actual or potential problems, including unexpected plant equipment degradation, damage, failure, malfunction or loss. Site documents that implement AMPs for license renewal will direct that an action request be prepared in accordance with those procedures whenever non-conforming conditions are found (*i.e.*, the acceptance criteria are not met). Equipment deficiencies are corrected through the initiation of a work order in accordance with plant procedures. Although equipment deficiencies may initially be documented by a work order, the corrective action process specifies that an action request also be initiated if required.

<u>Confirmation Process</u>. The focus of the confirmation process is on the follow-up actions that must be taken to verify effective implementation of corrective actions. The measure of effectiveness is in terms of correcting the adverse condition and precluding repetition of significant conditions adverse to quality. Plant procedures include provisions for timely evaluation of adverse conditions and implementation of any corrective actions required, including root cause determinations and prevention of recurrence where appropriate (*e.g.*, significant conditions adverse to quality). These procedures provide for tracking, coordinating, monitoring, reviewing, verifying, validating, and approving corrective actions, to ensure effective corrective actions are taken. The action request process is also monitored for potentially adverse trends. The existence of an adverse trend due to recurring or repetitive adverse conditions will result in the initiation of an action request. The AMPs required for license renewal would also be expected to uncover any unsatisfactory condition due to ineffective corrective action. Since the same 10 CFR Part 50, Appendix B, corrective action and confirmation process is applied for non-conforming safety-related and nonsafety-related SCs

subject to AMR for license renewal, the corrective action program is consistent with NUREG-1800.

Administrative Control. Aging management programs are administered through various plant implementation documents which are subject to administrative controls, including a formal review and approval process in accordance with the requirements of 10 CFR Part 50, Appendix B. The applicant stated the programs are, therefore, consistent with NUREG-1800.

3.0.4.2 Staff Evaluation

The staff reviewed the applicant's AMPs described in LRA Sections A15.1 and B1.3. The purpose of this review was to assure that the aging management activities were consistent with the staff's guidance described in NUREG-1800 Section A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)," regarding QA attributes of AMPs. Based on the staff's evaluation, the descriptions and applicability of the plant-specific AMPs and their associated quality attributes provided in the LRA, the staff concluded that the program descriptions are consistent with the staff's position, the SRP-LR and the Branch Technical Position discussed in IQMB-1.

3.0.4.3 Conclusion

On the basis of its review, as discussed above, the staff concluded that the QA attributes of the applicant's AMPs will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as requested by 10 CFR 54.21(a)(3). Specifically, the applicant described the quality attributes of the programs and activities for managing the effects of aging for both safety-related and nonsafety-related SSCs within the scope of license renewal and stated that the 10 CFR 50, Appendix B, QA program addresses the elements of corrective action, confirmation process, and administrative control. Therefore, the applicant's QA attributes for its AMPs are acceptable.

3.1 Aging Management of Reactor Vessel, Internals, and Reactor Coolant System

This section of the SER documents the staff's review of the applicant's AMR results for the reactor vessel, internals, and reactor coolant system components and component groups associated with the following systems:

- Class 1 piping/components system
- reactor vessel
- reactor vessel internals
- pressurizer
- steam generators
- non-Class 1 RCS components system

3.1.1 Summary of Technical Information in the Application

In LRA Section 3.1, the applicant provided AMR results for reactor vessel, internals, and reactor coolant system (RCS) components and component groups. In LRA Table 3.1.1, "Summary of Aging Management Evaluations in Chapter IV of NUREG-1801 for Reactor Coolant System," the applicant provided a summary comparison of its AMRs with the AMRs evaluated in the GALL Report for the reactor vessel, internals, and RCS components and component groups.

The applicant's AMRs incorporated applicable operating experience in the determination of aging effects requiring management (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 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.

3.1.2 Staff Evaluation

The staff reviewed LRA Section 3.1 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the reactor 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).

Also, the staff performed an onsite audit 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. Details of the staff's audit evaluations are documented in the PBNP audit and review report and are summarized in SER Section 3.1.2.1.

The staff also performed an onsite audit of 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 were consistent with the acceptance criteria in NUREG-1800 Section 3.1.2.2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated July 2001. The staff's audit evaluations are documented in the PBNP audit and review report and are summarized in SER Section 3.1.2.2.

The staff performed an onsite audit and 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 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 PBNP audit and review report and summarized in SER Section 3.1.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.1.2.3.

Finally, the staff reviewed the AMP summary descriptions in the FSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the reactor vessel, internals, and reactor coolant system components.

Table 3.1-1 below provides a summary of the staff's evaluation of components, aging effects/mechanisms, and AMPs listed in LRA Section 3.1 that are addressed in the GALL Report.

Table 3.1-1 Staff Evaluation for Reactor Vessel, Internals, and Reactor Coolant System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Reactor coolant pressure boundary components (Item Number 3.1.1-01)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue (See Section 3.1.2.2.1)
Steam generator shell assembly (Item Number 3.1.1-02)	Loss of material due to pitting and crevice corrosion	Inservice inspection; water chemistry	Steam Generator Integrity Program, Inservice Inspection Program, Water Chemistry Control Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.2)
Pressure vessel ferritic materials that have a neutron fluence greater than 10^{17}n/cm^2 (E>1 MeV) (Item Number 3.1.1-04)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with Appendix G of 10 CFR 50 and RG 1.99	TLAA	This TLAA is evaluated in Section 4.2, Reactor Vessel Neutron Embrittlement
Reactor vessel beltline shell and welds (Item Number 3.1.1-05)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor vessel surveillance	Reactor Vessel Surveillance Program, TLAA (see Section 4.2 and 4.4)	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.3)
Westinghouse and Babcock & Wilcox baffle/former bolts (Item Number 3.1.1-06)	Loss of fracture toughness due to neutron irradiation embrittlement and void swelling	Plant-specific	Reactor Vessel Internals Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.3)
Small-bore RCS and connected systems piping (Item Number 3.1.1-07)	Crack initiation and growth due to SCC, intergranular SCC, and thermal and mechanical loading	Inservice inspection, water chemistry, one-time inspection	Water Chemistry Control Program, Inservice Inspection Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.4)
Vessel shell (Item Number 3.1.1-10)	Crack growth due to cyclic loading	TLAA	TLAA	This TLAA is evaluated in Section 4.4, Fracture Mechanisms (See Section 3.1.2.2.5)
Reactor internals (Item Number 3.1.1-11)	Changes in dimension due to void swelling	Plant-specific	Reactor Vessel Internals Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.6)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
PWR core support pads, instrument tubes (bottom head penetrations), pressurizer spray heads, and nozzles for the steam generator instruments and drains (Item Number 3.1.1-12)	Crack initiation and growth due to SCC and/or primary water stress corrosion cracking (PWSCC)	Plant-specific	Water Chemistry Control Program, Reactor Coolant System Alloy 600 Inspection Program, Inservice Inspection Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.7)
Cast austenitic stainless steel (CASS) RCS piping (Item Number 3.1.1-13)	Crack initiation and growth due to SCC	Plant-specific	Water Chemistry Control Program, Inservice Inspection	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.7)
Pressurizer instrumentation penetrations and heater sheaths and sleeves made of nickel alloys (Item Number 3.1.1-14)	Crack initiation and growth due to PWSCC	Inservice inspection, water chemistry	Not Applicable	Not Applicable (See Section 3.1.2.2.7)
Westinghouse and B&W baffle/former bolts (Item Number 3.1.1-15)	Crack initiation and growth due to SCC and IASCC	Plant-specific	Water Chemistry Control Program, Reactor Vessel Internals Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.8)
Westinghouse and B&W baffle/former bolts (Item Number 3.1.1-16)	Loss of preload due to stress relaxation	Plant-specific	Reactor Vessel Internals Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.9)
Steam generator (PWRs only) feedwater impingement plate and support (Item Number 3.1.1-17)	Loss of section thickness due to erosion	Plant-specific	Water Chemistry Control Program, Steam Generator Integrity Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.10)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Alloy 600 steam generator tubes), repair sleeves, and plugs (Item Number 3.1.1-18)	Crack initiation and growth due to PWSCC, outside diameter stress corrosion cracking (ODSCC), and/or intergranular attack (IGA) or loss of material due to wastage and pitting corrosion, and fretting and wear: or deformation due to corrosion at tube support plate intersections	Steam generator tubing integrity, water chemistry	Water Chemistry Control Program, Steam Generator Integrity Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.11)
Tube support lattice bars made of carbon steel (Item Number 3.1.1-19)	Loss of section thickness due to FAC	Plant-specific	Water Chemistry Control Program, Steam Generator Integrity Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.12)
Carbon steel tube support plate (Item Number 3.1.1-20)	Ligament cracking due to corrosion	Plant-specific	Water Chemistry Control Program, Steam Generator Integrity Program	Consistent with GALL, which recommends further evaluation. (See Section 3.1.2.2.13)
Reactor vessel closure studs and stud assembly (Item Number 3.1.1-22)	Crack initiation and growth due to SCC and/or IGSCC	Reactor head closure studs	Inservice Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
CASS pump casing and valve body (Item Number 3.1.1-23)	Loss of fracture toughness due to thermal aging embrittlement	Inservice inspection	Inservice Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
CASS piping (Item Number 3.1.1-24)	Loss of fracture toughness due to thermal aging embrittlement	Thermal aging embrittlement of CASS	TLAA	This TLAA is evaluated in Section 4.4, Leak-Before-Break (See Section 3.1.2.1.1)
BWR piping and fittings; steam generator components (Item Number 3.1.1-25)	Wall thinning due to flow-accelerated corrosion	Flow-accelerated corrosion	Flow-Accelerated, Corrosion Program, Steam Generator Integrity Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
RCPB valve closure bolting, manway and holding bolting, and closure bolting in high pressure and high temperature systems (Item Number 3.1.1-26)	Loss of material due to wear; loss of preload due to stress relaxation; crack initiation and growth due to cyclic loading and/or SCC	Bolting integrity	Bolting Integrity Program, Inservice Inspection Program, Boric Acid Corrosion Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
CRD nozzle (Item Number 3.1.1-35)	Crack initiation and growth due to PWSCC	Ni-alloy nozzles and penetrations, water chemistry	Water Chemistry Control Program, Reactor Coolant System Alloy 600 Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
Reactor vessel nozzles safe ends and CRD housing; RCS components (except CASS and bolting) (Item Number 3.1.1-36)	Crack initiation and growth due to cyclic loading, and/or SCC, and PWSCC	Inservice inspection, water chemistry	Inservice Inspection Program, Water Chemistry Control Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
Reactor vessel internals CASS components (Item Number 3.1.1-37)	Loss of fracture toughness due to thermal aging, neutron irradiation embrittlement, and void swelling	Thermal aging and neutron irradiation embrittlement	Reactor Vessel Internals Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
External surfaces of carbon steel components in RCS pressure boundary (Item Number 3.1.1-38)	Loss of material due to boric acid corrosion	Boric acid corrosion	Boric Acid Corrosion Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
Steam generator secondary manways and handholds (carbon steel) (Item Number 3.1.1-39)	Loss of material due to erosion	Inservice inspection	Not Applicable	Not Applicable
Reactor internals, reactor vessel closure studs, and core support pads (Item Number 3.1.1-40)	Loss of material due to wear	Inservice inspection	Inservice Inspection Program, Thimble Tube Inspection Program, Reactor Vessel Internals Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Pressurizer integral support (Item Number 3.1.1-41)	Crack initiation and growth due to cyclic loading	Inservice inspection	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue
Upper and lower internals assembly (Westinghouse) (Item Number 3.1.1-42)	Loss of preload due to stress relaxation	Inservice inspection, loose part and/or neutron noise monitoring	Reactor Vessel Internals Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
Reactor vessel internals in fuel zone region (except Westinghouse and B&W baffle/former bolts) (Item Number 3.1.1-43)	Loss of fracture toughness due to neutron irradiation embrittlement, and void swelling	PWR vessel internals, water chemistry	Reactor Vessel Internals Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
Steam generator upper and lower heads, tubesheets, and primary nozzles and safe ends (Item Number 3.1.1-44)	Crack initiation and growth due to SCC, PWSCC and IASCC	Inservice inspection, water chemistry	Inservice Inspection Program, Water Chemistry Control Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
Vessel internals (except Westinghouse and B&W baffle/former bolts) (Item Number 3.1.1-45)	Crack initiation and growth due to SCC and IASCC	PWR vessel internals, water chemistry	Reactor Vessel Internals Program, Water Chemistry Control Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
Reactor internals (B&W screws and bolts) (Item Number 3.1.1-46)	Loss of preload due to stress relaxation	Inservice inspection, loose part monitoring	Not Applicable	Not Applicable
Reactor vessel closure studs and stud assembly (Item Number 3.1.1-47)	Loss of material due to wear	Reactor head closure studs	Inservice Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)
Reactor internals (Westinghouse upper and lower internal assemblies, CE bolts and tie rods) (Item Number 3.1.1-48)	Loss of preload due to stress relaxation	Inservice inspection, loose part monitoring	Reactor Vessel Internals Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.1.2.1)

The staff's review of the PBNP reactor vessel, internals, and RCS components and associated components followed one of several approaches. One approach, documented in SER Section 3.1.2.1, involves the staff's review of the AMR results for components in the reactor vessel, internals, and RCS components that the applicant indicated are consistent with the GALL Report and do not require further evaluation. Another approach, documented in SER Section 3.1.2.2, involves the staff's review of the AMR results for components in the reactor vessel, internals, and RCS components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.1.2.3, involves the staff's review of the AMR results for components in the reactor vessel, internals, and RCS components that the applicant indicated are not consistent with the GALL Report or are not addressed in the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the RCS components is documented in SER Section 3.0.3.

3.1.2.1 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 3.1.2.1, 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 reactor vessel, internals, and RCS components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- Flow-Accelerated Corrosion Program
- Inservice Inspection Program
- One-Time Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Reactor Coolant System Alloy 600 Inspection Program
- Reactor Vessel Internals Program
- Reactor Vessel Surveillance Program
- Steam Generator Integrity Program
- Systems Monitoring Program
- Thimble Tube Inspection Program
- Water Chemistry Control Program

Staff Evaluation. In LRA Tables 3.1.2-1 through 3.1.2-6, the applicant provided a summary of AMRs for Class 1 piping/components system, reactor vessel, reactor vessel internals, pressurizer, steam generators, and non-Class 1 RCS 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's audit of those AMRs with Notes A through E, 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, although different, is 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, although different, is 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 aging management program 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 PBNP 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.

3.1.2.1.1 Loss of Fracture Toughness Due to Thermal Aging Embrittlement

The staff's review of LRA Section 3.1 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 the discussion section of LRA Table 3.1.1, Item 24, the applicant stated that it does not have CASS RCS piping, but does have CASS primary loop elbows. The applicant stated that CASS thermal aging is addressed using a leak-before-break (LBB) evaluation method and that "significant margin exists between detectable flaw size and flaw instability." LBB 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 4.4 documents the staff's review of the applicant's evaluation of this TLAA. On that basis, the applicant concluded that an aging management program is not required to manage the aging effects of thermal embrittlement for CASS primary loop elbows.

The staff also noted that LRA Table 3.1.2-1, "Reactor Coolant System - Class 1 Piping/Components System - Summary of Aging Management Review," lists the primary loop elbows component type, but does not list loss of fracture toughness due to thermal aging embrittlement as an aging effect requiring management.

On the basis of its review, the staff determined that it does not agree with the applicant's conclusions because, for CASS piping, loss of fracture toughness due to thermal aging embrittlement is an aging effect requiring management in accordance with the criteria contained in 10 CFR 54.21(a)(3). This is further supported by the GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," which identifies acceptable aging management options as "enhanced volumetric examination to detect and size cracks or plant- or component-specific flaw tolerance evaluation." In addition, the staff found, with regard to the applicant's use of LBB evaluation method, that LBB is not equivalent to a flaw tolerance methodology because it assumes through wall leakage and, therefore, does not assure the safety function of pressure boundary integrity.

RAI 3.1.1-1. In RAI 3.1.1-1, dated March 30, 2005, the staff requested the applicant to clarify how it manages the aging effect of loss of fracture toughness due to thermal aging embrittlement for CASS primary loop elbows. During conversations with the staff, the applicant agreed to revise its position and perform flaw tolerance evaluations. This was identified as confirmatory item (CI) 3.1.1-1.

In its response to CI 3.1.1-1, by letter dated June 9, 2005, the applicant stated that PBNP will follow the recommendation of GALL AMP XI.M12, and that it will use enhanced volumetric examinations or a plant-specific or component-specific flaw tolerance evaluation to demonstrate that CASS primary loop elbows, potentially susceptible to thermal embrittlement, have adequate fracture toughness.

The staff found the applicant's response to RAI 3.1.1-1 acceptable as it results in actions consistent with the GALL Report recommendations. The staff's concern is resolved and, therefore, CI 3.1.1-1 is closed.

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 had been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the RCS 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 3.1.1 (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 found that, except for CASS piping, 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 found 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).

3.1.2.2 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 3.1.2.2, the applicant provided further evaluation of aging management as recommended by the GALL Report for reactor vessel, internals, and RCS components. The applicant provided information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material due to pitting and crevice corrosion
- loss of fracture toughness due to neutron irradiation embrittlement
- crack initiation and growth due to thermal and mechanical loading or stress corrosion cracking
- crack growth due to cyclic loading
- changes in dimension due to void swelling
- crack initiation and growth due to stress corrosion cracking or primary water stress corrosion cracking
- crack initiation and growth due to stress corrosion cracking or irradiation-assisted stress corrosion cracking
- loss of preload due to stress relaxation
- loss of section thickness due to erosion
- crack initiation and growth due to primary water stress corrosion cracking (PWSCC), outside diameter stress corrosion cracking (ODSCC), or intergranular attack (IGA) or loss of material due to wastage and pitting corrosion or loss of section thickness due to fretting and wear or denting due to corrosion of carbon steel tube support plate
- loss of section thickness due to flow-accelerated corrosion

- ligament cracking due to corrosion
- loss of material due to flow-accelerated 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 3.1.3.2. Details of the staff's audit are documented in the staff's PBNP audit and review report. The staff's evaluation is discussed below.

3.1.2.2.1 Cumulative Fatigue Damage

In LRA Section 3.1.2.2.1, 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.

3.1.2.2.2 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.1.2.2.2 against the criteria in SRP-LR Section 3.1.2.2.2.

In LRA 3.1.2.2.2, the applicant addressed loss of material of steam generator assemblies due to pitting and crevice corrosion.

SRP-LR Section 3.1.2.2.2 states that loss of material due to pitting and crevice corrosion could occur in the steam generator shell assembly. The existing program relied on control of water chemistry to mitigate corrosion and inservice inspections to detect loss of material. NRC Information Notice (IN) 90-04, "Cracking of the Upper Shell-to-Transition Cone Girth Welds in Steam Generators," states that if general corrosion pitting of the shell exists the existing program may not be sufficient. In that case, the GALL Report recommends augmented inspections to manage the aging effect.

The AMPs recommended by the GALL Report for managing the aging of steam generator assemblies due to pitting and crevice corrosion are GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," to detect loss of material, and GALL AMP XI.M2, "Water Chemistry," to mitigate corrosion. The GALL Report also recommends a plant-specific program to conduct augmented inspections.

The applicant stated that its Water Chemistry Control Program and inservice inspections performed in accordance with its ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, are used to manage loss of material due to pitting and crevice corrosion on the internal surfaces of the steam generator shell. The applicant also stated that it augments its Water Chemistry Control Program and inservice inspections with a plant-specific aging management program, the Steam Generator Integrity Program, that provides all-inclusive guidance for the management of steam generator assets.

The staff reviewed the applicant's Water Chemistry Control Program, ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, and Steam Generator Integrity

Program. Its evaluation of these programs is documented in SER Sections 3.0.3.2.1, 3.0.3.2.18, and 3.0.3.2.20.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.2. For those line items that apply to LRA Section 3.1.2.2.2, the staff found that the applicant is consistent with the GALL Report and 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).

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

The staff reviewed LRA Section 3.1.2.2.3 against the criteria in SRP-LR Section 3.1.2.2.3.

In LRA Section 3.1.2.2.3, the applicant addressed (1) loss of fracture toughness due to neutron irradiation embrittlement, (2) loss of fracture toughness due to irradiation embrittlement of the reactor vessel beltline shell and weld materials, and (3) loss of fracture toughness due to embrittlement for baffle/former bolts.

SRP-LR Section 3.1.2.2.3 states that certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3 and that TLAAs are required to be evaluated in accordance with 10 CFR 54.2.(c)(1). Secondly, SRP-LR Section 3.1.2.2.3 states that loss of fracture toughness due to neutron irradiation embrittlement could occur in the reactor vessel. A Reactor Vessel Surveillance Program monitors neutron irradiation embrittlement of the reactor vessel. Reactor Vessel Surveillance Programs are plant-specific, depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In accordance with 10 CFR 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Finally, the SRP-LR Section 3.1.2.2.3 states that loss of fracture toughness due to neutron irradiation embrittlement and void swelling could occur in Westinghouse and B&W baffle/former bolts.

In LRA Section 3.1.2.2.3.1, the applicant states that certain aspects of neutron irradiation embrittlement are TLAAs as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(1). SER Section 4.2 documents the staff's review of the evaluation of this TLAA.

In LRA Section 3.1.2.2.3.2, the applicant stated that loss of fracture toughness in reactor vessel beltline shell and weld materials due to neutron irradiation embrittlement was identified as an aging effect requiring management. The upper shell and nozzles are not subject to significant neutron irradiation exposure because of their physical distance from the reactor core. The limiting beltline material is the Unit 2 reactor vessel at the intermediate-to-lower shell beltline circumferential weld.

The AMP recommended by the GALL Report for managing loss of fracture toughness due to neutron irradiation embrittlement in the reactor vessel is GALL AMP XI.M31, "Reactor Vessel Surveillance," which complies with the requirements of 10 CFR 50, Appendices G and H, and 10 CFR 50.61.

The applicant stated that its Reactor Vessel Surveillance Program, in conjunction with TLAA analyses, effectively manages loss of fracture toughness in the beltline materials. The Reactor Vessel Surveillance Program provides adequate material property and neutron dosimetry data to predict fracture toughness in beltline materials at the end of the period of extended operation. In addition, equivalent margins analyses have been performed in accordance with 10 CFR 50 Appendix G methods. The staff's review of this program is documented in SER Section 3.0.3.2.17.

In LRA Section 3.1.2.2.3.3, the applicant stated that loss of fracture toughness due to neutron irradiation embrittlement was also identified as an aging effect requiring management for the baffle/former bolts. The Reactor Vessel Internals Program will be used to manage this aging effect.

Loss of fracture toughness due to neutron irradiation embrittlement could occur in the reactor vessel. A Reactor Vessel Materials Surveillance Program monitors neutron irradiation embrittlement of the reactor vessel. Reactor Vessel Surveillance Programs are plant-specific, depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. In accordance with 10 CFR 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Therefore, further staff evaluation is required for license renewal. NUREG-1801 recommends further evaluation of the reactor vessel materials surveillance program for the period of extended operation. The staff verified that the applicant proposed an adequate reactor vessel materials surveillance program for the period of extended operation. The staff's evaluation of this program is discussed in SER Section 3.0.3.2.17.

The limiting beltline material at PBNP is the intermediate-to-lower shell beltline circumferential weld of the Unit 2 reactor vessel. The applicant's Reactor Vessel Surveillance Program, in conjunction with TLAA analyses, effectively manages loss of fracture toughness in the beltline materials. The Reactor Vessel Surveillance Program provides adequate material property and neutron dosimetry data to predict fracture toughness in beltline materials at the end of the period of extended operation. The analyses, as discussed in SER Section 4.2, for upper shelf energy and pressurized thermal shock provide assurance that beltline material toughness values in the reactor vessel will remain at acceptable levels through the period of extended operation. The staff reviewed the applicant's Reactor Vessel Surveillance Program. Its evaluation is documented in SER Section 3.0.3.2.17.

During the 1998 refueling outage, the entire population of 728 Type 347 stainless steel baffle/former bolts was selected for inspection at Unit 2. A total of 175 bolts were replaced with Type 316 stainless steel bolts during the outage. The Westinghouse Owners Group developed an NRC-approved methodology, WCAP-15029-P-A, to determine number and distribution of intact and functional baffle bolts required to ensure safe plant operation. Plant-specific applications of the Westinghouse methodology were performed in support of the inspection and replacement programs at Unit 2.

GALL Section IV.B2.4-f recommends plant-specific aging management. The applicant stated that, because of its change to Type 316 stainless steel baffle/former bolts in 1998, no further inspections of Unit 2 bolts are planned. However, in its letter dated July 12, 2004, the applicant stated that it will continue to monitor and participate in industry initiatives (MRP activities) with regard to reactor vessel internals to support aging management for the baffle/former bolts.

The staff concluded that the applicant's LRA commitment is acceptable because: (1) it will apply industry guidelines that will ensure that inspections capable of detecting degradation prior to a loss of component intended function will be used, (2) it will allow the staff to review the applicant's inspection plans for the reactor vessel internals as based on industry recommendations, and (3) it will provide the staff an opportunity to resolve with the applicant any issues that may arise with the inspection plan.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.3. For those line items that apply to LRA Section 3.1.2.2.3, the staff found that the applicant is consistent with the GALL Report and has 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).

3.1.2.2.4 Crack Initiation and Growth Due to Thermal and Mechanical Loading or Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.4 against the criteria in SRP-LR Section 3.1.2.2.4.

In LRA Section 3.1.2.2.4, the applicant stated that crack initiation and growth due to SCC was identified as an aging effect requiring management in small-bore (less than 4-inch NPS) RCS piping and branch lines. Aging management of service-induced cracking will be accomplished by a combination of the Water Chemistry Control Program and the Inservice Inspection Program. PBNP implemented a Risk-Informed Inservice Inspection Program and, as part of this transition, some small-bore RCS locations were identified for inspection. These inspections of small-bore RCS piping will meet the intent of the one-time inspections referenced in NUREG-1800.

SRP-LR Section 3.1.2.2.4 states that the GALL Report recommends that a plant-specific destructive examination or a nondestructive examination (NDE) that permits inspection of the inside surfaces of the piping be conducted to ensure that cracking has not occurred and the component intended function will be maintained during the period of extended operation. The applicant should verify that service-induced weld cracking is not occurring in small-bore piping. A one-time inspection of a sample of locations is an acceptable method to ensure that the aging effect is not occurring and that the component's intended function will be maintained during the period of extended operation. Per ASME Code Section XI, 1995 Edition, Examination Category B-J or B-F, small-bore piping, defined as piping less than 4-inch NPS, does not receive volumetric inspection.

The AMPs recommended by the GALL Report are GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," to detect loss of material, and GALL AMP XI.M2, "Water Chemistry," to mitigate SCC.

The applicant stated that its Water Chemistry Control Program and inservice inspections performed in accordance with its ASME Code Section XI, Subsections IWB, IWC, and IWD, Inservice Inspection Program, are used to manage crack initiation and growth due to thermal and mechanical loading or stress corrosion cracking. The staff reviewed the applicant's Water Chemistry Control Program and ASME Code Section XI, Subsections IWB, IWC, and IWD, Inservice Inspection Program. Its evaluation is documented in SER Sections 3.0.3.2.20 and 3.0.3.2.1, respectively.

The staff's review of LRA Section 3.1.2.2.4 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.

The applicant stated that Westinghouse had performed a generic aging management evaluation of Class 1 piping and associated pressure boundary components for the Westinghouse Owners Group. The applicant stated that Westinghouse Generic Topical Report (GTR), "Aging Management Review for Class 1 Piping and Associated Pressure Boundary Components," WCAP-14575-A, was approved by the staff.

RAI 3.1.2-1. LRA Section 3.1 states that WCAP-14575-A and 14574-A were approved by the staff. In RAI 3.1.2-1, dated November 17, 2004, the staff requested the applicant to indicate the dates of the approval letters/safety evaluation for the subject WCAPs.

In its response, dated January 25, 2005, the applicant stated that the approval letters for WCAP-14575-A and 14574-A were dated November 8, 2000, and October 26, 2000, respectively. The staff's review found that the subject GTRs were approved by the staff on the dates specified. Therefore, the staff concluded that the applicant appropriately used generic topical reports acceptable to the staff in its aging management review for the RCS and pressurizer. The staff's concern described in RAI 3.1.2-1 is resolved.

The applicant also stated that the RI-ISI Program inspections of piping welds less than 4-inch NPS will include volumetric examinations, with the exception of socket welded connections. Because no meaningful volumetric inspection technique exists for the geometry presented by socket welds, a surface examination will be performed. The staff notes that plant experience at Susquehanna Steam Electric Station (Susquehanna), Units 1 and 2, involved the successful ultrasonic examination (UT) of small-bore piping socket welds to detect cracking. The licensee had worked with the Electric Power Research Institute to develop a go/no-go method to detect cracking in the socket welds for the 1-inch vent lines for the reactor recirculation piping. The UT method was successful in identifying cracking at Susquehanna, and a number of socket welds were removed from service due to potential short-term cracking from fatigue.

RAI 3.1.2-2. LRA Section 3.1 states that meaningful volumetric inspection techniques do not exist for socket welds in the Class 1 piping. In RAI 3.1.2-2, dated November 17, 2004, the staff requested the applicant to consider the Susquehanna operating experience and discuss the applicability of UT of socket-welded joints in 1-inch piping at PBNP. If the applicant determined that UT is not suitable, the staff requested the applicant's basis and justification for the determination.

In its response, dated January 25, 2005, the applicant stated that the Susquehanna UT technique shows promise in situations dealing with frequent fatigue-related socket-welded joint failures. The technique is not an ASME Code-acceptable inspection, as it does not meet the inspection requirements for a volumetric examination, and has not been thoroughly investigated nor accepted by the industry. The applicant stated that, because the UT technique cannot characterize indications, its application can result in rejecting socket welds that may otherwise be acceptable, as was the case at Susquehanna.

Additionally, the applicant provided a more in-depth account of the socket-weld failures that have occurred at PBNP. It stated that three 2-inch socket-weld cracks were identified in the auxiliary feedwater pump recirculation lines downstream of the pressure reducing orifices following a system modification that allowed an increase in the pump recirculation flow rates. Another socket-weld failure occurred in a 3/4-inch socket weld in a drain line connection in the safety-injection/containment spray system full-flow test line following a system modification. Two 3/8-inch socket weld cracks were identified on the steam generator channel head drain line isolation valve following replacement of the Unit 1 steam generators. The applicant stated that the failures resulted in minor leakage identified by plant personnel during walkdowns and post-modification testing. The staff concluded from the socket-weld failure history provided by the applicant that the statement "no significant socket weld failures" refers to short-term failures resulting from modifications rather than failures caused by aging effects requiring management.

The applicant further stated that the staff approved the Risk-Informed Inservice Inspection (RI-ISI) methodology to monitor the Class 1 piping systems that collectively use the socket welds, and that to deploy the UT methodology of testing would result in unnecessary radiation exposure to plant personnel. The applicant cited the following passage from the staff's safety evaluation of its RI-ISI Program:

> The objective of inservice inspection required by the ASME Code, Section XI, is to identify conditions that are precursors to leaks and ruptures in the pressure boundary that may impact plant safety. The RI-ISI program is judged to meet this objective.

The staff agreed that the socket-weld failures resulted from failure mechanisms other than those caused by aging and that sufficient monitoring is in place such that no significant safety condition exists. The staff, therefore, concluded that using the Susquehanna UT methodology would result in unnecessary radiation exposure and that the response to RAI 3.1.2-2 is acceptable. The staff's concern described in RAI 3.1.2-2 is resolved.

The applicant indicated that the staff had specified Renewal Applicant Action Items that were required as part of its acceptance of WCAP-14575-A, and that the items are discussed in LRA Table 3.1.0-1. For the Class 1 piping and associated pressure boundary components, the LRA indicated that there were 10 staff-identified action items, and similarly, 10 items for the pressurizer. The applicant's responses to the action items were acceptable with two exceptions. The applicant's response to action item (6) in LRA Table 3.1.0-1 reflected its earlier position regarding UT on small-bore piping socket welds. Based on its response to RAI 3.1.2-2, the staff considered this item resolved.

Under Renewal Applicant Action Item (4) of LRA Table 3.1.0-3, the staff discusses the development of SCC in the bolting materials. The staff stated that to take credit for the criteria in EPRI Report NP-5769, the applicant must state that the acceptable yield strengths for the quenched and tempered low-alloy steel bolting materials (SA-193, Grade B7) are in the range of 105 to150 ksi. In its plant-specific response, the applicant stated that because the maximum yield strength is not specified for this bolting material, absolute assurance that the yield strength of the bolting would not exceed 150 ksi cannot be provided. The applicant stated that control of contaminants and bolt torquing will ensure that SCC will not occur, and that a review of inservice inspection and general documentation databases supports the conclusion that no pressure boundary bolting degradation due to SCC is occurring. Staff experience with this phenomenon is that design changes to the bolting configuration and surface coatings aid in the prevention of SCC. Also, the extent and type of nondestructive examination performed on the bolting is important in determining if cracking is active.

RAI 3.1.2-4. Under the plant-specific response in LRA Table 3.1.0-3 for Renewal Applicant Action Item (4), the applicant stated that absolute assurance could not be provided that the yield strength of the SA-193, Grade B7 bolting, is under 150 ksi. Furthermore, it is stated that because the inservice inspection database results show that no cracking is occurring, SCC is not considered an aging effect requiring management for the pressurizer bolting. In RAI 3.1.2-4, dated November 17, 2004, the staff requested the applicant to explain in detail the type, extent, and frequency of nondestructive examinations on this pressure-retaining bolting performed under the Inservice Inspection Program.

In its response, dated January 25, 2005, the applicant stated that the pressurizer bolting is inspected in accordance with the requirements of item Table IWB-2500-1, category B-G-2, item B7.20. The ASME Code requires a visual examination (VT-1) at each interval.

The applicant's inspection frequency is once per interval, consistent with the inspection frequency listed in ASME Code Section XI. The staff concluded that sufficient inspections exist for SA-193, Grade B7 pressurizer bolting such that the effects of aging are managed, and considers the response to RAI 3.1.2-4 acceptable. The staff's concern described in RAI 3.1.2-4 is resolved.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.4. For those line items that apply to LRA Section 3.1.2.2.4, the staff found that the applicant is consistent with the GALL Report and has 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).

3.1.2.2.5 Crack Growth Due to Cyclic Loading

In LRA Section 3.1.2.2.5, the applicant stated that underclad cracking in carbon/low-alloy steel that was clad with austenitic stainless steel using weld-overlay processes was identified as an aging effect requiring management and is considered a TLAA as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(2). SER Section 4.4 documents the staff's review of the applicant's evaluation of this TLAA.

3.1.2.2.6 Changes in Dimension Due to Void Swelling

The staff reviewed LRA Section 3.1.2.2.6 against the criteria in SRP-LR Section 3.1.2.2.6.

In LRA Section 3.1.2.2.6, the applicant addressed changes in dimension due to void swelling that could occur in reactor internals components.

SRP-LR Section 3.1.2.2.6 states that the GALL Report recommends that changes in dimension due to void swelling in reactor internals components be evaluated to ensure that this aging effect is adequately managed. The GALL Report recommends that a plant-specific AMP be evaluated to manage the effects of changes in dimension due to void swelling and the loss of fracture toughness associated with swelling.

The applicant stated that the void swelling of reactor vessel internals is managed by its Reactor Vessel Internals Program. Further, the applicant stated that transmission electron microscopy studies of thin foils prepared from an intact baffle/former bolt and locking device removed from the Unit 2 reactor vessel internals in 1999 indicated that voids were present in the threaded end of the bolt but not in the head or the 304 stainless steel locking device. The maximum void volume observed in the 347 stainless steel bolt material, 0.03 percent, is small and preliminary extrapolation to the end of extended life using a simple square law suggests that void swelling should not be a concern. The industry is currently developing technical guidance to address the issue of void swelling. The applicant committed to further understanding of this aging effect through industry programs that may provide additional bases for supplemental examinations or component-specific evaluations.

The staff evaluated the applicant's Reactor Vessel Internals Program. Its evaluation is documented in SER Section 3.0.3.2.15. The staff found the applicant's approach for managing changes in dimension due to void swelling acceptable because the approach will be based on the guidelines developed by the ongoing industry activities related to void swelling. The applicant committed to implement the appropriate recommendations resulting from the industry efforts. The applicant also committed, in its letter dated July 12, 2004, that the revised program description, including a comparison with the 10 program elements of the NUREG-1801 program, will be submitted to the NRC for approval two years prior to the period of extended operation.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.6. For those line items that apply to LRA Section 3.1.2.2.6, the staff found that the applicant is consistent with the GALL Report and has 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).

3.1.2.2.7 Crack Initiation and Growth Due to Stress Corrosion Cracking or Primary Water Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.7 against the criteria in SRP-LR Section 3.1.2.2.7.

In LRA Section 3.1.2.2.7.1, the applicant stated that the core support pads and the bottom head instrument penetrations are fabricated from Alloy 600. Crack initiation and growth of the bottom head penetrations due to SCC/PWSCC is managed by a combination of the Water Chemistry Control Program and the Reactor Coolant System Alloy 600 Inspection Program. The Reactor Coolant System Alloy 600 Inspection Program is a plant-specific program, which includes participation in industry initiatives related to management of Alloy 600 penetration cracking issues. The core support pads are susceptible to crack initiation and growth due to SCC/PWSCC and are managed by a combination of the Water Chemistry Control Program and the Inservice Inspection Program.

In LRA Section 3.1.2.2.7.2, the applicant stated that the primary loop elbows are CASS material and are subject to aging effects. The Water Chemistry Control Program monitors and controls primary water chemistry in accordance with the guidelines of EPRI TR-105714 and, therefore, effectively manages crack initiation and growth due to SCC. Additionally, in LRA

Section 3.1.2.2.7.3, the applicant stated that there are no components fabricated from Alloy 600 in the pressurizers.

The staff reviewed the applicant's Water Chemistry Control Program, the Reactor Coolant System Alloy 600 Inspection Program, and the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. Its evaluation is documented in SER Sections 3.0.3.2.20, 3.0.3.2.15, and 3.0.3.2.1, respectively. The staff found that these programs will manage the aging effects of crack initiation and growth due to SCC/PWSCC in the RCS components.

In LRA Section 3.1.2.2.7.1, the applicant stated that the reactor vessel leak detection line is outside the primary pressure boundary and, is therefore, not within the scope of license renewal. The pressurizer spray head performs no license renewal intended function at PBNP, including Appendix R considerations (the pressurizer cooldown rate required for an Appendix R scenario is achievable without a functioning spray head). The steam generator instrument nozzles are low-alloy steel, not Alloy 600 or stainless steel and, therefore, are not included in this component group.

The staff reviewed the applicant's claims that these components are not within the scope of the license renewal scoping and screening. This review is documented in SER Sections 2.3.1.2.2 and 2.3.1.4.2, and response to RAI 2.3.1.2-1. On the basis of its review, the staff determined that these components are not safety-related and, therefore, are not within the scope of license renewal.

The applicant identified cracking due to SCC and flaw growth as applicable aging effects for Alloy 600 components that are exposed to primary water with a temperature greater than 480 °F. NUREG-1801 also identified crack initiation and growth and primary water stress corrosion cracking as an aging effect/mechanism.

The applicant credited its Water Chemistry Control Program to manage this aging effect. In the Water Chemistry Control Program, the applicant credits the EPRI TR-10574, Revision 4, and TR-102134, Revision 5. This program controls concentrations of known chemical species such as halogens, sulfates, and dissolved oxygen below the levels known to cause degradation. The program provides assurance that an acceptable level of contaminants and oxygen is maintained in the systems and components covered by the program and, therefore, minimizes the occurrence of aging effects.

In addition, the applicant credited either the Reactor Coolant System Alloy 600 Inspection Program or the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program inspections to identify and correct degradation in Class 1, 2, and 3 piping, components, and their integral attachments. These programs include periodic visual, surface and/or volumetric examinations and leakage tests of all Class 1, 2, and 3 pressure-retaining components, and their integral attachments, including welds, pump casings, valve bodies, and pressure-retaining bolting. The GALL Report recommends the applicant to provide a plant-specific AMP or participate in industry programs to determine appropriate aging management. The Reactor Coolant System Alloy 600 Inspection Program is a plant-specific program for PBNP that includes participation in industry initiatives related to management of Alloy 600.

In LRA Section 3.1.2.2.7.2, the applicant stated the primary loop elbows are CASS material and are subject to these aging effects. The applicant proposed to manage these aging effects using the Water Chemistry Control Program and ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

The staff reviewed the applicant's Water Chemistry Control Program and the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. Its evaluation is documented in SER Sections 3.0.3.2.20 and 3.0.3.2.1, respectively. On the basis of its review, the staff found that these programs will manage the aging effects of crack initiation and growth due to SCC/PWSCC in the RCS components.

In LRA Section 3.1.2.2.7.3, the applicant stated that there are no components fabricated from Alloy 600 in the pressurizer and, therefore, this line item was not used. Instrument penetrations, heater well tubes, and adapters are stainless steel. During the audit, the staff held discussions with the applicant's technical staff. The applicant confirmed that there are no Alloy 600 components in the pressurizers. On this basis, the staff found this explanation is acceptable.

The staff's review of LRA Section 3.1.2.2.7 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.

The staff reviewed Renewal Applicant Action Item (10) of LRA Table 3.1.0-1. The staff's safety evaluation for WCAP-14575-A notes that, if a repair or replacement was performed on CASS, a new LBB analysis would be required to determine the effect of thermal aging on CASS components. In its response to Renewal Applicant Action Item (10), the applicant indicated that the LBB analyses were revised utilizing a methodology consistent with the original analyses.

Furthermore, the applicant indicated that plant process control procedures (design control, repair/replacement, and welding) will be revised to ensure that repair or replacement of Class 1 piping components (welded connections or CASS would require a new LBB analysis based on the replacement process and/or material properties. Because the applicant indicated that the revised LBB analyses had been completed, the staff questioned whether the revision to the plant process control procedures is still required.

RAI 3.1.2-3. PBNP's plant-specific response, LRA Table 3.1.0-1 Item (10), indicated that plant process control procedures (*i.e.*, design control, repair/replacement, and welding) will be revised to ensure that repair or replacement of Class 1 piping components welded connections or CASS would require a new LBB analysis based on replacement process and/or material properties. Prior to that statement, it was indicated that the subject LBB analyses addressing steam generator replacement, power uprate, and a 60-year operating period had been revised. Because these LBB analyses revisions typically address the effects of thermal aging on CASS components, in RAI 3.1.2-3, dated November 17, 2004, the staff requested the applicant to explain in detail why the revisions to the procedures were necessary. The staff also requested the applicant to advise if the revised LBB analyses addressed the effects of thermal aging on CASS components. If the revisions to the plant control procedures were required per plant administrative program controls, the applicant was requested to provide a commitment in the LRA stating that the subject revisions would be completed prior to the period of extended operation.

In its response, dated January 25, 2005, the applicant stated that the revised LBB analyses account for the effects of thermal aging of CASS materials. The applicant also stated that Applicant Action Item (10) of the NRC Safety Evaluation for WCAP-14575-A, "Aging Management Evaluation for Class 1 Piping and Associated Pressure Boundary Components," requires that the provisions for management of thermal aging (LBB analyses) include addressing the impacts of repairs/replacements of CASS components on the LBB analyses, making the proposed revisions to PBNP procedures/processes necessary. The applicant also indicated that LRA Section B2.1.1 identifies the necessary program enhancements to address maintenance of the LBB analyses.

The staff concluded that the applicant is complying with the requirements to maintain the LBB analyses, that a documented commitment was listed, and that the response to RAI 3.1.2-3 is acceptable. The staff's concerns described in RAI 3.1.2-3 are resolved.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.7. For those line items that apply to LRA Section 3.1.2.2.7, the staff found that the applicant is consistent with the GALL Report and has 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).

3.1.2.2.8 Crack Initiation and Growth Due to Stress Corrosion Cracking or Irradiation-assisted Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.8 against the criteria in SRP-LR Section 3.1.2.2.8.

In LRA Section 3.1.2.2.8, the applicant addressed crack initiation and growth due to SCC or irradiation-assisted stress corrosion cracking (IASCC) that could occur in baffle/former bolts in the reactor.

SRP-LR Section 3.1.2.2.8 states that crack initiation and growth due to SCC or IASCC could occur in baffle/former bolts in the reactors. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

In LRA Section 3.1.2.2.8, the applicant stated that crack initiation and growth due to SCC and IASCC were identified as aging effects requiring management for the baffle/former bolts. A combination of the Water Chemistry Control Program and the Reactor Vessel Internals Program is used to manage this aging effect.

In LRA Table 3.1.2-3, the applicant identified that cracking is an applicable aging effect for the baffle/barrel former bolts that are exposed to the borated water environment and categorized the AMR for these components as a need for plant-specific aging management. GALL line Item IV.B2.4-c for baffle/former bolts also recommends a plant-specific program with appropriate augmented visual inspections be used to manage cracking in this component. Historically, VT-3 visual examinations have not identified baffle/former bolt cracking because cracking occurs at the juncture of the bolt head and shank, which is not accessible for visual inspection. Ultrasonic testing (UT) examinations of the baffle/former bolts have identified cracking in several plants.

The applicant credits a combination of the Water Chemistry Control Program and the Reactor Vessel Internals Program to manage this aging effect. LRA Section B2.1.17 discusses the applicant's Reactor Vessel Internals Program. During the 1998 refueling outage, the entire population of 728 Type 347 stainless steel baffle/former bolts was selected for inspection by UT at Unit 2. A total of 175 bolts were replaced with Type 316 stainless steel bolts during the outage. These bolts were part of a pre-qualified minimum bolt pattern for PBNP.

The applicant used the Westinghouse Methodology (WCAP-15029-P-A) in support of the inspection and replacement programs at Unit 2. However, the applicant stated in LRA Section B2.1.17 that it will "Actively participate in industry groups studying reactor vessel internals materials degradation issues, such as the EPRI MRP RI-ITG and Westinghouse Owner's Group. Implement NRC approved industry activities resulting from the MRP, as appropriate, to manage any applicable aging effects identified through the EPRI MRP effort." In addition, the applicant stated in its letter, dated July 12, 2004, that it will submit an inspection plan for the Reactor Vessel Internals Program for NRC review and approval at least 24 months prior to entering the period of extended operation.

The staff concluded that the applicant's LRA commitment is acceptable because: (1) it will apply industry guidelines that will ensure that inspections capable of detecting degradation prior to a loss of component intended function will be used, (2) it will allow the staff to review the applicant's inspection plans for the Reactor Vessel Internals Program as based on the industry recommendations, and (3) it will provide the staff an opportunity to resolve with the applicant any issues that may arise with the inspection plan.

The staff found that, based on the program identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.8. For those line items that apply to LRA Section 3.1.2.2.8, the staff found that the applicant is consistent with the GALL Report and has 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).

3.1.2.2.9 Loss of Preload Due to Stress Relaxation

The staff reviewed LRA Section 3.1.2.2.9 against the criteria in SRP-LR Section 3.1.2.2.9.

In LRA Section 3.1.2.2.9, the applicant addressed loss of preload due to stress relaxation that could occur in baffle/former bolts in the reactor.

SRP-LR Section 3.1.2.2.9 states that loss of preload due to stress relaxation could occur in baffle/former bolts in the reactor. The GALL Report recommends a plant-specific AMP to ensure that these aging effects are adequately managed.

In LRA Section 3.1.2.2.9, the applicant credits the Reactor Vessel Internals Program for managing loss of preload. Loss of preload due to stress relaxation was identified as an aging effect requiring management of baffle/former bolts. GALL recommended that visual VT-3 inspection needs to be augmented to detect relevant conditions of stress relaxation because only the heads of the baffle/former bolts are visible, and a plant-specific aging management program is required. The applicant stated that aging will be managed by the Reactor Vessel Internals Program. The applicant will continue to participate in industry initiatives regarding managing aging effects applicable to reactor vessel internals as stated in its letter dated July 12, 2004.

The staff concluded that the applicant's LRA commitment is acceptable because: (1) it will apply industry guidelines that will ensure that inspections capable of detecting degradation prior to a loss of component intended function will be used, (2) it will allow the staff to review the applicant's inspection plans for the reactor vessel internals as based on the industry recommendations, and (3) it will provide the staff an opportunity to resolve with the applicant any issues that may arise with the inspection plan.

The staff found that, based on the program identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.9. For those line items that apply to LRA Section 3.1.2.2.9, the staff found that the applicant is consistent with the GALL Report and has 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).

3.1.2.2.10 Loss of Section Thickness Due to Erosion

The staff reviewed LRA Section 3.1.2.2.10 against the criteria in SRP-LR Section 3.1.2.2.10.

In LRA Section 3.1.2.2.10, the applicant addressed loss of section thickness due to erosion that could occur in steam generator feedwater impingement plates and supports.

SRP-LR Section 3.1.2.2.10 states that loss of section thickness due to erosion could occur in steam generator feedwater impingement plates and supports. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed.

The applicant stated that this component group is not applicable for the steam generator design. The feedwater delivery to the steam generators at PBNP is through feed rings to J-tubes. The feed rings and J-tubes perform no license renewal intended function.

The staff's review of LRA Section 3.1.2.2.10 identified an area 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.

RAI 3.1.1-2. In RAI 3.1.1-2, dated March 30, 2005, the staff requested the applicant to justify why the SG feedrings and associated J-tubes would not be scoped in the license renewal. During conversations with the staff, the applicant agreed to scope and manage the aging effects associated with the SG feedrings and J-tubes. This was identified a confirmatory item (CI) 3.1.1-2.

In its response to CI 3.1.1-2, by letter dated June 9, 2005, the applicant stated that J-nozzles, feedrings, and feedring supports have been added to the scope of license renewal to address a potential issue, where failures of nonsafety-related components could affect the safety-related SG tubing. Therefore, the aging management programs for these components need to ensure that the feedring components stay in place and not fall on the SG tubes. The applicant will age-manage the SG feedrings, J-nozzles, and feedring supports using the Water Chemistry Control Program and the Steam Generator Integrity Program. The Steam Generator Integrity Program provides for various inspections of the secondary side of the SGs, which will provide verification that aging effects are not progressing, thereby ensuring that the feedring and J-nozzles remain in place.

The staff found the applicant's response to RAI 3.1.1-2 acceptable because it brought the J-nozzles, feedrings, and feedring supports into the scope of license renewal and appropriately manages the aging effects to assure that the component will not prevent safety-related components from performing its associated safety functions. The staff's concern is resolved and, therefore, CI 3.1.1-2 is closed.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.10. For those line items that apply to LRA Section 3.1.2.2.10, the staff found that the applicant is consistent with the GALL Report and has 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).

3.1.2.2.11 Crack Initiation and Growth Due to PWSCC, ODSCC, or IGA or Loss of Material Due to Wastage and Pitting Corrosion or Loss of Section Thickness Due to Fretting and Wear or Denting Due to Corrosion of Carbon Steel Tube Support Plate

The staff reviewed LRA Section 3.1.2.2.11 against the criteria in SRP-LR Section 3.1.2.2.11.

In LRA Section 3.1.2.2.11, the applicant addressed crack initiation and growth due to PWSCC, SCC, IGA, or loss of material due to wastage and pitting corrosion that could occur in nickel-based alloy components of the steam generator tubes and plugs.

SRP-LR Section 3.1.2.11 states that crack initiation and growth due to PWSCC, ODSCC, IGA, or loss of material due to wastage and pitting corrosion or deformation due to corrosion could occur in Alloy 600 components of the steam generator tubes, repair sleeves, and plugs. All PWR licensees have committed voluntarily to a SG degradation management program described in NEI 97-06; these guidelines are currently under staff review. The GALL Report recommends that an AMP, based on the recommendations of staff-approved NEI 97-06 guidelines or alternative regulatory basis for SG degradation management, be developed to ensure that this aging effect is adequately managed.

In LRA Section 3.1.2.2.11, the applicant stated that cracking due to PWSCC, IGA/IGSCC, and loss of material due to pitting and wear had been identified as aging effects requiring management for the steam generator tubes and plugs. The applicant stated that these aging effects will be managed by the Water Chemistry Control Program and the Steam Generator Integrity Program.

Unit 1 has two replacement SGs, which were installed in 1984. The Unit 1 SGs use thermally treated Alloy 600 tubes. Unit 2 has two replacement SGs which were installed in 1996. The Unit 2 SGs use thermally treated Alloy 690 tubes. Alloy 690 plugs are used to repair tubes.

The staff's review of aging effects that are applicable to the steam generators includes the review of aging management during the period of extended operation for the following internal and external aging effects: (1) cracking and (2) loss of material.

Steam generator (SG) aging management incorporates provisions of NEI 97-06, "Steam Generator Program Guidelines." The industry guidelines include an assessment of degradation mechanisms considering the operating experience from similar SGs to identify all potential degradation mechanisms that should be considered during inspection. For each identified mechanism, NEI 97-06 defines the inspection techniques, measurement uncertainty and sampling strategies. The industry guidelines provide criteria for the qualification of personnel, specific techniques and the associated acquisition and analysis of data, including procedures, probe selection, analyses protocols and reporting data. Performance criteria which pertain to structural integrity, accident induced leakage, and operational leakage are specified.

The Steam Generator Integrity Program includes guidance on assessment of degradation mechanisms, inspection, tube integrity, maintenance, repair, leakage monitoring as well as control of water chemistry. Water chemistry control of both primary and secondary water is an integral component outlined in NEI 97-06 and is a method to limit age-related degradation. NEI 97-06 identifies a provision for monitoring secondary-side SG components to ensure that failure of a secondary-side component will not impact the ability of the SG to fulfill its safety-related function.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.11. For those line items that apply to LRA Section 3.1.2.2.11, the staff found that the applicant is consistent with the GALL Report and has 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).

3.1.2.2.12 Loss of Section Thickness Due to Flow-accelerated Corrosion

The staff reviewed LRA Section 3.1.2.2.12 against the criteria in SRP-LR Section 3.1.2.2.12.

In the LRA Section 3.1.2.2.12, the applicant addressed loss of section thickness due to flow-accelerated corrosion (FAC) that could occur in tube support lattice bars made of stainless steel or Alloy 600.

SRP-LR Section 3.1.2.2.12 states that loss of section thickness due to FAC could occur in tube support lattice bars made of carbon steel. The GALL Report recommends that a plant-specific AMP be evaluated and, on the basis of the guidelines of GL 97-06, an inspection program for steam generator internals be developed to ensure that this aging effect is adequately managed.

The staff's review of LRA Section 3.1.2.2.12 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.

The applicant identified that the Unit 1 SG anti-vibration bars are fabricated from chrome-plated Alloy 600 and the Unit 2 anti-vibration bars are fabricated from stainless steel. These components are identified by the applicant as being potentially susceptible to cracking in the secondary water environment. The applicant proposes to utilize a combination of the Water Chemistry Control Program and the Steam Generator Integrity Program to manage aging of this component. The SG tube support plates are stainless steel and are also subjected to the same aging effect and environment.

RAI 3.1-1. In RAI 3.1-1, dated November 18, 2004, the staff requested the applicant to provide details regarding how the Steam Generator Integrity Program would support monitoring of the anti-vibration bars for cracking.

In its response, dated January 6, 2005, the applicant stated that the Water Chemistry Control Program conforms to the guidelines in EPRI TR-102134, Revision 5, and that the Water Chemistry Control Program mitigates aging effects, such as cracking due to SCC, by controlling the environment to which the secondary side of the SGs is exposed. The applicant stated that aging effects are minimized by controlling the chemical species that cause the underlying mechanisms that result in this aging effect and that the program provides assurance that an elevated level of contaminants and oxygen does not exist on the secondary-side of the SGs, and thereby minimizes this aging effect. The applicant indicated that the Water Chemistry Control Program has been in use since early in the plant's operation and has been effective at maintaining the desired system water chemistry and detecting abnormal conditions, which have been corrected in an expedient manner. The applicant also concluded that verification inspections are not required by the Water Chemistry Control Program, because the secondary-side of the SGs is not a low-flow or stagnant area and, therefore, the Water Chemistry Control Program alone effectively manages this aging effect on the secondary-side of the SGs.

Further, the applicant stated that the Steam Generator Integrity Program is utilized to conservatively augment the Water Chemistry Control Program to verify the effectiveness of water chemistry. The applicant indicated that the Steam Generator Integrity Program is intended to provide a general condition assessment of the secondary side of the steam generators. The applicant stated that, although the anti-vibration bars are inaccessible for visual inspection due to the construction of the tube bundle and their location within the tube bundle, periodic visual inspections of accessible areas are performed to verify the integrity of secondary-side components. The applicant also stated that the secondary-side inspections will assess representative material environment combinations similar to the inaccessible components in the SGs.

The staff found the applicant's response acceptable. Secondary-side visual inspection will be performed on representative material/environment combinations that may be used to provide indication of degradation. The staff's concern described in RAI 3.1-1 is, therefore, resolved.

The staff confirmed that the lattice bars are not made of carbon steel. The staff considered industry experience and agrees that lattice bars made of stainless steel or Alloy 600 are not susceptible to flow assisted corrosion. Furthermore, based on industry experience the staff agrees that components made from stainless steel or Alloy 600 in secondary treated water with temperatures greater than 120 °F are susceptible to cracking due to SCC. The staff's evaluation of the Steam Generator Integrity and Water Chemistry Control Programs are documented in Sections 3.0.3.2.18 and 3.0.3.2.20, respectively. The staff agrees that the Water Chemistry Control Program is expected to mitigate cracking and that the Steam Generator Integrity Program is expected to confirm that cracking is not occurring.

On the basis of its review of the steam generator integrity and water chemistry control programs and the fact that the component is made from either stainless steel or Alloy 600, the staff found that the applicant appropriately evaluated AMR results involving plant-specific programs to address these aging mechanisms.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.12. For those line items that apply to LRA Section 3.1.2.2.12, the staff found that the applicant is consistent with the GALL Report and has 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).

3.1.2.2.13 Ligament Cracking Due to Corrosion

The staff reviewed LRA Section 3.1.2.2.13 against the criteria in SRP-LR Section 3.1.2.2.13.

In the LRA Section 3.1.2.2.13, the applicant addressed ligament cracking due to corrosion that could occur in carbon steel components in the SG tube support plate.

The applicant stated that carbon steel components are not part of the SG tube support-plates. However, cracking due to SCC was identified as the aging effect requiring management for the stainless steel tube support plates in the PBNP steam generators. The applicant also stated that this aging effect is managed by the Water Chemistry Control Program and augmented by the Steam Generator Integrity Program, which provides for secondary-side inspections to verify the effectiveness of water chemistry control.

The staff confirmed that these components are not made of carbon steel. Furthermore, based on industry experience, the staff agrees that components made of stainless steel or Alloy 600 in secondary treated water, with temperatures greater than 120 °F, are susceptible to cracking due to SCC. The staff's evaluation of the Steam Generator Integrity Program and the Water Chemistry Control Program are documented in Section 3.0.3.2.18 and 3.0.3.2.20, respectively. The staff agrees that the Water Chemistry Control Program will mitigate cracking and that the steam generator integrity program will confirm that cracking is not occurring.

On the basis of its review of the Steam Generator Integrity and Water Chemistry Control Programs, the staff found that the applicant had appropriately evaluated AMR results involving plant-specific programs to address these aging mechanisms.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.1.2.2.13. For those line items that apply to LRA Section 3.1.2.2.13, the staff found that the applicant is consistent with the GALL Report and 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).

3.1.2.2.14 Loss of Material Due to Flow-Accelerated Corrosion

Loss of material due to flow-accelerated corrosion is only applicable to PWR Combustion Engineering designs. Therefore, this item is not applicable for Units 1 and 2.

3.1.2.2.15 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).

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

Summary of Technical Information in the Application. In LRA Tables 3.1.2-1 through 3.1.2-6, the applicant provided additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report or are not addressed in the GALL Report.

As documented under RAI 2.1-1 in SER Section 2.1, by letter dated April 29, 2005, the applicant changed the methodology used to determine the nonsafety-related SCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). As a result of the implementation of the scoping methodology changes, the applicant identified no changes to LRA Tables 3.1.2-1 through 3.1.2-6.

In LRA Tables 3.1.2-1 through 3.1.2-6, 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 will be maintained consistent with the CLB during the period of extended operation.

The staff's review of LRA Section 3.1 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 LRA Tables 3.1.2-1 and 3.1.2-4, the applicant listed, as Note H, the following components:

- orifices and reducers (stainless steel)
- piping and fittings less than 4-inch NPS (wrought stainless steel)
- piping and fittings greater than or equal to 4-inch NPS (wrought stainless steel)
- primary loop elbows (cast stainless steel)
- reactor coolant pump thermal barrier flange (wrought stainless steel)
- thermowells (stainless steel)

- valves less than 4-inch NPS (cast stainless steel)
- valves greater than or equal to 4-inch NPS (cast stainless steel)
- pressurizer heater shell and heater sheath (stainless steel)
- pressurizer instrument nozzles (stainless steel)
- pressurizer lower head (carbon steel with stainless steel cladding)
- pressurizer manway cover (carbon steel with stainless steel disc insert)
- pressurizer relief nozzle (carbon steel with stainless steel cladding)
- pressurizer relief nozzle safe end (stainless steel)
- pressurizer safety nozzle (carbon steel with stainless steel cladding)
- pressurizer safety nozzle safe end (stainless steel)
- pressurizer shell (alloy steel with stainless steel cladding)
- pressurizer spray nozzle (carbon steel with stainless steel cladding)
- pressurizer spray nozzle safe end (stainless steel)
- pressurizer spray nozzle thermal sleeve (stainless steel)
- pressurizer surge nozzle (carbon steel with stainless steel cladding)
- pressurizer surge nozzle safe end, thermal sleeve (stainless steel)
- pressurizer upper head (carbon steel with stainless steel cladding)
- reactor coolant pump casing and main flange (cast stainless steel)

Note H items are defined as those whose aging effect was not in NUREG-1801 for this component, material, and environment combination. The applicant's plant-specific program designated Notes 5 and 21 for those components. Note 5 states that "The material/environment combination and/or aging effect is not identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation." Note 21 states that "Materials science supports loss of material due to pitting (stagnant or low-flow conditions) and crevice corrosion for all temperatures. The Water Chemistry Control Program is credited for managing the aging effects for all temperatures."

Published literature indicates that pitting corrosion and crevice corrosion may occur in ASME Code Class 1 stainless steel or NiCrFe components under exposure to aggressive, oxidizing environments. Normally, the presence of elevated dissolved oxygen and/or aggressive ionic impurity concentrations is necessary to create these oxidizing environments in the RCS. The applicant indicated that the Water Chemistry Control Program manages the aging effects of corrosion/pitting. The Water Chemistry Control Program is discussed in SER Section 3.0. Under the program description section of GALL AMP XI.M2, it is stated that the water chemistry programs are generally effective in removing impurities from intermediate-flow and high-flow areas. The report identifies those circumstances in which the water chemistry programs may not be effective in low-flow or stagnant-flow areas. In certain cases, GALL AMP XI.M2 recommends verification of the effectiveness of the chemistry control program to ensure significant degradation is not occurring and that the component intended function will be maintained during the period of extended operation. For specific cases, an acceptable verification program is a one-time inspection of selected components at susceptible locations in the system.

RAI 3.1.2-5. LRA Tables 3.1.2-1 and 3.1.2-4 indicate that the Water Chemistry Control Program is used to manage the effects of loss of material due to corrosion in low-flow and stagnant areas for a variety of stainless and cast stainless materials. These components are designated by Note H with footnotes 5 and 21. NUREG-1801, XI.M2, recommends a One-Time

Inspection Program to validate the effectiveness of the Water Chemistry Control Program for low-flow and stagnant areas. In RAI 3.1.2-5, dated November 17, 2004, the staff requested the applicant to discuss how the aging effect of loss of material for components specified under Note H of the two listed tables is managed for low-flow/stagnant areas because NUREG-1801, XI.M2, specifies that the mitigating effects of a Water Chemistry Control Program alone are not sufficient.

In its response, dated January 25, 2005, the applicant stated that the GALL Report (GALL) tables did not reference the aging effect of corrosion in these materials because the primary coolant environment is strictly controlled through the Water Chemistry Control Program. The applicant also referenced NRC statements made in its safety evaluations for WCAP-14575-A, Aging Management Evaluation for Pressurizers, along with LRA Applicant Action Item 3.2.2.1-1. In the safety evaluation, the staff agreed that hydrogen overpressure can mitigate the aggressive effect of oxygen in creviced geometries on the internal pressurizer surfaces. Applicant Action Item 3.2.2.1-1 states that applicants for license renewal should provide a basis in their plant-specific applications about how their Water Chemistry Control Program will provide for a sufficient level of hydrogen overpressure to manage crevice corrosion of the internal surfaces of their pressurizer.

The staff's review of the plant-specific response to Applicant Action Item 3.2.2.1-1 indicated that the applicant maintains strict control of hydrogen overpressure to minimize crevice corrosion for pressurizers and other Class 1 components through the implementation of the Water Chemistry Control Program. Furthermore, published literature indicates that the use of hydrogen water chemistry inhibits the onset of cracking and corrosion and has been used effectively on many reactor coolant systems in operating reactors to date.

Based on the applicant's use of hydrogen water chemistry, the staff concluded that the aging effects of corrosion in low-flow areas are managed through the Water Chemistry Control Program , which acts as a reasonable deterrent measure in place of a One-Time Inspection Program. The staff's concern described in RAI 3.1.2-5 is resolved.

3.1.2.3.1 Reactor Coolant System Components That Have No Aging Effect - Tables 3.1.2-1 through 3.1.2-6

In LRA Tables 3.1.2-1 through 3.1.2-6, the applicant identified line items where no aging effects were identified as a result of the aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from carbon steel, low-alloy steel, Alloy 600, stainless steel, copper alloy, or stainless steel clad material were exposed to air or to an inert gas (*e.g.*, nitrogen). Neither air nor inert gas is identified in the GALL Report as an environment for these components and materials. No aging effects are considered to be applicable to carbon steel, low-alloy steel, Alloy 600, stainless steel, copper alloy, or stainless steel clad components exposed to air, or to an inert gas environment.

On the basis of its review of current industry research and operating experience, the staff found that dry air on metal will not result in aging that will be of concern during the period of extended operation. These RCS components are exposed to high-temperature internal flow, which creates a dry air environment. Stainless steel and nickel-based alloy components in air or an inert gas environment are not susceptible to general corrosion that would affect their intended function. Therefore, the staff concluded that there are no applicable aging effects requiring management for carbon steel, low-alloy steel, Alloy 600, stainless steel, copper alloy, or stainless steel clad components exposed to air, or to an inert gas environment.

3.1.2.3.2 Class 1 Piping/Components System - Aging Management Evaluation - Table 3.1.2-1

The staff reviewed LRA Table 3.1.2-1, which summarizes the results of AMR evaluations for the Class 1 piping/components system component groups.

The Class 1 piping/components system experiences loss of material due to corrosion of stainless steel, wrought stainless steel, low-alloy and nickel-based alloy materials for the following component types:

- thermowells
- thermal barrier
- orifices and reducers
- piping and fittings
- primary loop elbows
- valves
- piping weld and vent connections
- RCP pump (casing and main flange)
- RCP pump (thermal barrier flange)

For those components requiring staff review, the environments are listed below:

- treated water - primary (140 °F<T<480 °F)(internal)
- treated water - primary (T>480 °F)(internal)
- treated water - other

The applicant proposed to manage the Class 1 piping/components loss of material aging effects by using the Water Chemistry Control Program. The staff's evaluation of this AMP is documented in SER Section 3.0.3.2.20. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that the effects of loss of material (pitting and crevice corrosion) on stainless steel, cast stainless steel, low-alloy stainless steel cladding, and nickel-based alloy components in treated water are effectively managed using the Water Chemistry Control Program. On this basis, the staff found that management of loss of material in Class 1 piping/components system is acceptable.

The applicant proposed to manage cracking in stainless steel, cast stainless steel, nickel-based alloy and low-alloy steel clad components exposed to treated water - primary (140 °F<T<480 °F)(internal) and treated water - primary (T>480 °F)(internal) using the Water Chemistry Control Program, Closed-Cycle Cooling Water System Surveillance Program, and the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

The staff reviewed the Water Chemistry Control Program, Closed-Cycle Cooling Water System Surveillance Program, and ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. The evaluations are documented in SER Sections 3.0.3.2.20, 3.0.3.2.9, and 3.0.3.2.1, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that the effects of cracking in stainless steel, cast stainless steel, nickel-based alloy and low-alloy steel clad components exposed to treated water are effectively managed using the Water Chemistry Control Program and the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. On this basis, the staff found that management of cracking in Class 1 piping/components system is acceptable.

The applicant proposed to manage erosion of stainless steel orifices and reducers exposed to treated water using the One-Time Inspection Program. The applicant stated that when used to detect the aging effect of loss-of-wall thickness due to erosion, the One-Time Inspection Program uses wall thickness as a parameter that must be monitored and visual inspection (VT-3) and/or volumetric inspection (RT/UT) as the appropriate inspection method. Volumetric NDE methods to measure wall thickness are currently used by industry to detect and monitor erosion/corrosion in piping systems at nuclear power plants. The applicant stated that it will use wall thickness measurements and compare those wall thickness measurements against criteria based upon design criteria for the subject component.

The staff reviewed the One-Time Inspection Program. Its evaluation is documented in SER Section 3.0.3.2.13. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that the effects of erosion of stainless steel orifices and reducers exposed to treated water are effectively managed using the One-Time Inspection Program. On this basis, the staff found that management of loss of material in Class 1 piping/components system using this program is acceptable.

In LRA Table 3.1.2-1, the applicant listed as Note F for the following components that correlate to material not in GALL:

- piping welds and vent connections (Alloy 690 and 82/152) (Unit 2 only)
- reactor coolant pumps thermal barrier flange (wrought stainless steel)
- valves less than 4-inch NPS (wrought stainless steel)
- valves greater than or equal to 4-inch NPS (wrought stainless steel)

Plant-specific Note 5 accompanied each of the above components. Note 5 states:

> The material/environment combination and/or aging effect is not identified in NUREG-1801. The aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation.

The staff compared the component items in LRA Table 3.1.2-1 against Table 1 of GALL. The applicant's AMR specified the appropriate AMP suggested by GALL that correlated to the aging effect for the component's material. For the piping welds made out of Alloy 690 and 82/152 weld material, the applicant specified the Reactor Coolant System Alloy 600 Program, the Water Chemistry Control Program and the Inservice Inspection Program as the AMPs to manage the effects of aging. Though the GALL Volume 2 line item number does not agree with the GALL material type (cast stainless steel), the appropriate plant-specific AMP was specified by the applicant for the material types.

For component C2.4-b, GALL Table 2 lists crack initiation and growth/SCC as the aging effect/mechanisms. Though the material in Table 2 for that component identification is cast stainless steel, the applicant appropriately identified the aging effect for its plant-specific material and the appropriate AMP recommended by GALL in Table 1. Based on the above discussion, the staff concluded that the items listed as Note F in the applicant's aging management review are consistent with the intent of GALL. The staff concluded that this consistency with GALL provides reasonable assurance the effects of aging will be managed and, therefore, the AMP is acceptable for the period of extended operation.

3.1.2.3.3 Reactor Vessel - Aging Management Evaluation - Table 3.1.2-2

The staff reviewed LRA Table 3.1.2-2, which summarizes the results of AMR evaluations for the reactor vessel component groups.

Loss of material due to wear and corrosion for Alloy 600 and stainless steel components including the core support pads and the RV components exposed to primary treated water (T > 480 °F) is proposed to be managed by using the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program or the Water Chemistry Control Program.

Inspections under the requirements of the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program provide a combination of volumetric and visual examinations that will detect loss of material and confirm the effectiveness of the Water Chemistry Control Program.

The applicant proposed to manage cracking due to SCC and flaw growth for stainless steel and Alloy 600 components including bottom-mounted instrument guide tubes, core support pads, and seal table fittings exposed to primary treated water (T > 480 °F) (T < 140 °F) by using the Water Chemistry Control Program and the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

The applicant proposed to manage loss of mechanical closure integrity due to stress relaxation for low-alloy steel components including closure studs, nuts, and washers exposed to containment (external) by using the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

The staff reviewed the applicant's Water Chemistry Control Program and the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. Its evaluation is documented in SER Sections 3.0.3.2.20 and 3.0.3.2.1, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that the effects of aging are effectively managed by using the Water Chemistry Control Program and the ASME Code Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program. On this basis, the staff found that aging management in the reactor vessel components group is acceptable.

3.1.2.3.4 Reactor Vessel Internals - Aging Management Evaluation - Table 3.1.2-3

The staff reviewed the LRA Table 3.1.2-3, which summarizes the results of AMR evaluations in the SRP-LR for the reactor vessel internals component groups.

The applicant proposed to manage loss of material in stainless steel material of reactor vessel internals component types exposed to primary treated water (T>480 °F) using the Water Chemistry Control Program.

The staff reviewed the applicant's Water Chemistry Control Program. Its evaluation is documented in SER Section 3.0.3.2.20. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that the loss of material in stainless steel for component types of reactor vessel internals exposed surfaces and crevice locations exposed to treated water is effectively managed using the Water Chemistry Control Program. On this basis, the staff found that management of loss of material in reactor vessel internals using this program is acceptable.

The applicant proposed to manage loss of fracture toughness due to neutron irradiation embrittlement in stainless steel components in the fuel zone, including the flux thimbles reactor vessel upper core plate and the reactor vessel upper core plate fuel alignment pin exposed to primary treated water (T>480 °F) using the Reactor Vessel Internals Program.

The applicant stated that it performed destructive examinations of baffle/former bolts removed during the 1999 refueling outage and these examinations suggest that void swelling and loss of fracture toughness should not present a concern during the period of extended operation. The reactor vessel upper core plate and the reactor vessel upper core plate fuel alignment pin components are not included among the components subject to significant irradiation embrittlement because of their remote location from the fuel zone.

The staff found that, based on its review of the description of the applicant's Reactor Pressure Vessel Internals Program and on the commitment that the applicant will provide the Reactor Pressure Vessel Internals Program for staff review prior to the period of extended operation, as discussed in SER Section 3.0.3.2.16, management of loss of fracture toughness using the Reactor Vessel Internals Program is acceptable.

3.1.2.3.5 Pressurizer - Aging Management Evaluation - Table 3.1.2-4

The staff reviewed LRA Table 3.1.2-4, which summarizes the results of AMR evaluations for the pressurizer component groups.

The pressurizer experiences loss of material of stainless steel, and carbon steel or alloy steel with stainless steel cladding or disc insert for the following component types:

- heater well
- heater sheath
- instrument nozzles
- manway cover
- relief nozzle
- relief nozzle safe ends
- safety nozzle
- safety nozzle safe ends
- shell
- spray nozzle
- spray nozzle safe ends
- nozzle thermal sleeve
- surge nozzle
- surge nozzle thermal sleeve
- surge nozzle safe ends
- upper and lower head

Those components requiring staff review are exposed to an environment of primary treated water with temperature greater than 480 °F.

The applicant proposed to manage the pressurizer loss of material aging effects by using the Water Chemistry Control Program. During the audit the applicant clarified that the use of only the Water Chemistry Control Program was considered sufficient to manage these components because industry operating experience has not identified material loss on these components.

The staff reviewed the applicant's Water Chemistry Control Program. Its evaluation is documented in SER Section 3.0.3.2.20. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that the effects of loss of material of stainless steel, and low-alloy carbon steel with stainless steel cladding components in treated borated water are effectively managed using the Water Chemistry Control Program. On this basis, the staff found that management of loss of material in the pressurizer using this program is acceptable.

3.1.2.3.6 Steam Generators - Aging Management Evaluation - Table 3.1.2-5

The staff reviewed LRA Table 3.1.2-5, which summarizes the results of AMR evaluations for the steam generator component groups.

The SG experiences loss of material of stainless steel, Alloy 600/690, and alloy steel materials for the following component types:

- components in contact with primary water
- feedwater nozzles
- steam flow limiter

For those components requiring staff review, the environments are listed below:

- treated water - primary (T>480 °F)(internal)
- treated water - secondary (T>120 °F)(internal)

The applicant proposed to manage the SG loss of material aging effects by using the Steam Generator Integrity Program and Water Chemistry Control Program.

The applicant also proposed to manage cracking of Alloy 600, alloy steel, and stainless steel for component types of anti-vibration bars, feedwater nozzles, transition cone girth weld (Unit 1 only), tube sheet, upper and lower shell, elliptical head, transition cone, tube support plates, and steam outlet nozzle exposed to secondary treated water with temperatures greater than 120 °F by using the Water Chemistry Control Program, Steam Generator Integrity Program, and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

The staff's review of LRA Table 3.1.2-5 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 LRA Table 3.1.2-5, the applicant identified that the SG divider plates are fabricated from Alloy 600/690 and that these components are potentially susceptible to cracking in the primary water environment. The applicant proposed to use the Water Chemistry Control Program to manage this aging effect.

RAI 3.1-3. In RAI 3.1-3, dated November 18, 2004, the staff requested the applicant to justify why the Water Chemistry Control Program alone is sufficient to manage aging for Alloy 600/690 sub-components.

RAI 3.1-4. In RAI 3.1-4, dated November 18, 2004, the staff requested the applicant to justify why inspections are not used to support the Water Chemistry Control Program for SG divider plates.

In its response, dated January 6, 2005, the applicant stated that the divider plate acts as a flow baffle with minimal primary stresses resulting from the low differential pressure across the plate and that the main contributor to operating stress results from thermal stress. The applicant indicated that inspection could be performed in connection with other SG inspection activities, but that dose considerations would preclude inspection. The applicant also indicated that there has been no industry operating experience indicating problems with stress corrosion cracking of the divider plate.

The staff concluded that use of the Water Chemistry Control Program was sufficient to manage age-related degradation of this component because this component is not located in a low-flow or stagnant area, there is no industry experience of failure, and, if necessary, inspection could be performed during steam generator inspection activities. The staff's concerns described in RAIs 3.1-3 and 3.1-4 are resolved.

The applicant identified that aging would be managed for a number of secondary-side steam generator components (*i.e.,* steam outlet nozzle, feedwater nozzle) potentially susceptible to loss of material by the Water Chemistry Control Program and Steam Generator Integrity Program. Other components (*i.e.*, steam generator blowdown piping and secondary shell penetrations) also identified as potentially susceptible to loss of material would be managed by the Water Chemistry Control Program and Steam Generator Integrity Program.

RAI 3.1-2. In RAI 3.1-2, dated November 18, 2004, the staff requested the applicant to clarify if the Steam Generator Integrity Program (steam generator secondary-side inspection) was intended to meet the inservice inspection requirements for those secondary-side components that do not use the Inservice Inspection Program. The staff also requested additional details regarding how the Steam Generator Integrity Program could manage aging of components such as the blowdown piping nozzle and secondary shell penetrations.

In its response, dated January 6, 2005, the applicant stated that the Inservice Inspection Program was only identified for those components that are within the Inservice Inspection Program scope. Items such as the blowdown nozzles and secondary penetrations are not within scope. The applicant indicated that inservice inspection was identified to supplement water chemistry and the Steam Generator Integrity Program because the inservice inspections were capable of detecting loss of material, although detection of loss of material is not the primary focus of the inservice inspection exam. The applicant relies on the Water Chemistry Control Program and the Steam Generator Integrity Program to manage loss of material for all of these components. The applicant indicated that the Water Chemistry Control Program maintains an environment limiting the potential susceptibility for loss of material and that the Steam Generator Integrity Program employs secondary-side inspection. The applicant indicated that where secondary components are inaccessible, similar materials in a similar environment are used to evaluate the potential for degradation of those inaccessible components.

The staff found the applicant's response acceptable. The applicant will establish a framework that is expected to manage loss of material using a combination of a low-susceptibility environment created by the Water Chemistry Control Program to minimize the potential for degradation and inspection by the Steam Generator Integrity Program and, when possible, the Inservice Inspection Program, to identify the potential for degradation. The staff's concern described in RAI 3.1.2 is resolved.

LRA Table 3.1.2-5 identifies Notes H, 21 and J, 5 for loss of material in stainless steel, carbon steel clad with stainless steel and Alloy 600/690 materials. For these AMRs only the Water Chemistry Control Program is identified as the applicable AMP. PBNP personnel have indicated that the basis for using only the mitigative Water Chemistry Control Program is that the program does not require lack of aging effect validation if the flow is moderate or high. The staff considers this a misinterpretation of the GALL AMP. The GALL Report identifies stagnant or low flow conditions as examples of when it would be appropriate to validate the effectiveness of the Water Chemistry Control Program. The GALL Report utilizes this example to demonstrate when a validation of aging management program is appropriate, but does not define, by default, when a validation should not be used. In conditions of moderate or high flow, an SSC could have crevice or other locations of low or stagnant flow. Furthermore, all systems are shut down and flow is reduced to stagnant conditions at some point in the SCC's service life. Therefore, this was identified as open item (OI) 3.1.1-3.

In its response to OI 3.1.1-3, by letter dated June 10, 2005, the applicant stated that, for SG components in contact with primary water, the same material types in the same environments exist in the RV, the vessel internals, the pressurizer, and the Class 1 piping and components. In all of these systems and components, loss of material is proposed to be managed with the Water Chemistry Control Program alone (and was found by the staff to be acceptable in the draft safety evaluation report (D-SER)). The primary side of the SG is no different. Stainless steel and nickel alloy are corrosion-resistant materials, and industry and plant-specific operating experience has shown that loss of material is not an active degradation mechanism on primary-side components, primarily due to the strict water chemistry controls used in PWRs. Other components in this same environment are routinely inspected (*i.e.*, SG tubes), and these inspections would provide leading indications to the susceptibility of these materials to loss of material.

The staff reviewed the applicant's characterization and re-evaluated the GALL Report for loss of material in stainless steel, carbon steel clad with stainless steel and Alloy 600/690 materials and concluded that the applicant's response is acceptable. The staff's concern is resolved and, therefore, OI 3.1.1-3 is closed.

3.1.2.3.7 Non-Class 1 RCS Components - Aging Management Evaluation - Table 3.1.2-6

The staff reviewed LRA Table 3.1.2-6, which summarizes the results of AMR evaluations for the non-Class 1 RCS components groups.

The non-Class 1 RCS components experience loss of material of stainless steel, copper alloy (Zn<15%), copper alloy (Zn>15%), and CASS materials for the following component types:

- flow indicators
- instrument valve assemblies
- piping and fittings
- heat exchangers
- valve bodies
- tanks
- thermowells

For those components requiring staff review, the environments are listed below:

- treated water - borated (T<140 °F)(internal)
- treated water - other (internal)
- treated water - primary (T>480 °F)(internal)
- treated water - primary (T<140 °F)(internal)
- treated water - primary (140 °F<T<480 °F)(internal)
- air and gas - wetted (T<140 °F)(internal)
- treated water - other (stagnant)(internal)

The applicant proposed to manage the non-Class 1 RCS components loss of material aging effects by using the Water Chemistry Control Program, Closed-Cycle Cooling Water System Surveillance Program and One-Time Inspection Program.

The staff reviewed the Water Chemistry Control Program, Closed-Cycle Cooling Water System Surveillance Program and One-Time Inspection Program. Its evaluations are documented in SER Sections 3.0.3.2.20, 3.0.3.2.9 and 3.0.3.2.13, respectively. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that the effects of loss of material on stainless steel, copper alloys, and CASS material for components exposed to treated borated water, treated water, and wetted air and gas are effectively managed using the Water Chemistry Control Program, Closed-Cycle Cooling Water System Surveillance Program, and One-Time Inspection Program. On this basis, the staff found that management of loss of material in non-Class 1 RCS components using these programs is acceptable.

The applicant proposed to manage cracking of stainless steel for component types of instrument valve assemblies, pipings, fittings, and valve bodies exposed to primary treated water with temperatures greater than 480 °F and temperatures between 140 °F and 480 °F by using the Water Chemistry Control Program and the One-Time Inspection Program.

The staff reviewed the applicant's Water Chemistry Control Program and One-Time Inspection Program. Its evaluations are documented in SER Sections 3.0.3.2.20 and 3.0.3.2.13, respectively. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that the effects of cracking on instrument valve assemblies, pipings, fittings, and valve bodies for components exposed to primary treated borated water with temperatures greater than 480 °F, and temperatures between 140 °F and 480 °F are effectively managed using the Water Chemistry Control Program and One-Time Inspection Program. On this basis, the staff found that management of cracking in non-Class 1 RCS components using these programs is acceptable.

Conclusion. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving material, environment, AERM, and AMP 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).

3.1.3 Conclusion

On the basis of its review, the staff concluded that the applicant demonstrated that the aging effects associated with the RCS components will be adequately managed so that the intended functions will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable FSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the reactor coolant systems as required by 10 CFR 54.21(d).

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 engineered safety features (ESF) and component groups associated with the following systems:

- safety injection system
- containment spray system
- residual heat removal system
- containment isolation components system

3.2.1 Summary of Technical Information in the Application

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

The applicant's AMRs incorporated applicable operating experience in the determination of 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 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.

3.2.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the ESF 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).

Also, the staff performed an onsite audit 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 confirm that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMPs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. The staff's audit evaluations are documented in the PBNP audit and review report and are summarized in SER Section 3.2.2.1.

The staff also performed an onsite audit of those 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 NUREG-1800 Section 3.2.2.2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated July 2001. The staff's audit evaluations are documented in the PBNP audit and review report and are summarized in SER Section 3.2.2.2.

The staff performed an onsite audit and conducted a technical review of the remaining AMRs that were not consistent with or not addressed in the GALL Report. The 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 evaluation is documented in the PBNP audit and review report and is summarized in SER Section 3.2.2.3. The staff's evaluation of its technical review is also documented in SER Section 3.2.2.3.

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

Table 3.2-1 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 3.2.1-01)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue (See Section 3.2.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Components in containment spray (PWR only), standby gas treatment (BWR only), containment isolation, and emergency core cooling systems (Item Number 3.2.1-03)	Loss of material due to general corrosion	Plant-specific	Not Applicable	Not Applicable (See Section 3.2.2.2.2)
Components in containment spray (PWR only), standby (BWR only), containment isolation, and emergency core cooling systems (Item Number 3.2.1-05)	Loss of material due to pitting and crevice corrosion	Plant-specific	Water Chemistry Control Program; One-Time Inspection Program	Consistent with GALL, which recommends further evaluation (See Section 3.2.2.2.3)
Containment isolation valves and associated piping (Item Number 3.2.1-06)	Loss of material due to microbiologically influenced corrosion	Plant-specific	Not Applicable	Not Applicable (See Section 3.2.2.2.4)
High-pressure safety injection (charging) pump miniflow orifice (Item Number 3.2.1-08)	Loss of material due to erosion	Plant-specific	One-Time Inspection Program	Consistent with GALL (See Section 3.2.2.2.6)
External surfaces of carbon steel components (Item Number 3.2.1-10)	Loss of material due to general corrosion	Plant-specific	System Monitoring Program	Consistent with GALL, which recommends further evaluation (See Section 3.0.3.3.2)
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	Not Applicable	Not Applicable
Component serviced by open-cycle cooling system (Item Number 3.2.1-12)	Local loss of material due to corrosion and/or buildup of deposit due to biofouling	Open-cycle cooling water system	Not Applicable	Not Applicable

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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	One-Time Inspection Program; Closed-Cycle Cooling Water System Surveillance Program; Water Chemistry Control Program	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.1)
Pumps, valves, piping, fittings, and tanks in containment spray and emergency core cooling systems (Item Number 3.2.1-15)	Crack initiation and growth due to SCC	Water chemistry	Water Chemistry Control Program; One-Time Inspection Program	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.1)
Carbon steel components (Item Number 3.2.1-17)	Loss of material due to boric acid corrosion	Boric acid corrosion	Boric Acid Corrosion Program	Consistent with GALL, 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, loss of preload due to stress relaxation and crack initiation and growth due to cyclic loading or SCC	Bolting integrity	Bolting Integrity Program	Consistent with GALL, which recommends no further evaluation (See Section 3.2.2.1)

The staff's review of the ESF components and associated components 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 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 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 that the applicant indicated are not consistent with the GALL Report or are not addressed in the GALL Report. The staff's review of AMPs that are credited to manage or monitor aging effects of the ESF 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

Summary of Technical Information in the Application. In LRA Section 3.2.2.1, 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 ESF components:

- Bolting Integrity Program
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Periodic Surveillance and Preventive Maintenance Program
- Systems Monitoring Program
- Water Chemistry Control Program

Staff Evaluation. In LRA Tables 3.2.2-1 through 3.2.2-4, the applicant provided a summary of AMRs for the safety injection system, containment spray system, residual heat removal system, and containment isolation components system 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 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's audit of those AMRs with Notes A through E, 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, although different, is 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, although different, is 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 determined 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 E indicated that the AMR line item is consistent with the GALL Report for material, environment, and aging effect, but a different aging management program 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 PBNP 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 is 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 have been reviewed and are evaluated in the GALL Report, and (3) identified those aging effects for the ESF 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 3.2.1 (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 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 found 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 found 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).

3.2.2.2 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 ESF. 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
- changes in properties due to elastomer degradation
- local loss of material due to erosion
- buildup of deposits due to 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 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 3.2.2.2. Details of the staff's audit are documented in the staff's PBNP audit and review report.

3.2.2.2.1 Cumulative Fatigue Damage

In LRA Section 3.2.2.2.1, 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.

3.2.2.2.2 Loss of Material Due to General Corrosion

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 for external and internal environments in ESF components.

SRP-LR Section 3.2.2.2.2 states that loss of material due to general corrosion could occur in the containment spray, containment isolation valves and associated piping, and the external surfaces of carbon steel components. The GALL Report recommends further evaluation on a plant-specific basis to ensure that the aging effect is adequately managed.

In LRA Section 3.2.2.2.2, the applicant stated that the loss of material due to general corrosion line item was not used, although PBNP does have carbon steel components in the ESF. The applicant addresses this aging effect for external environments in Item Number 3.2.1-10, and credits the Systems Monitoring Program for aging management. Internal environments are addressed in loss of material due to pitting and crevice corrosion, for which the Water Chemistry Control Program and/or the One-Time Inspection Program are credited.

As documented in the audit and review report, the applicant stated that one-time inspections for general corrosion will monitor component wall thickness. Monitoring methods will include visual (VT-3) and/or volumetric (RT/UT) examinations. Visual inspections will be performed only when the components are drained/opened and the component surface of interest is accessible. If degradation is identified through a visual inspection, additional NDE may be performed to characterize the degradation and determine the extent of the condition. The applicant stated that the NDE exams will be performed as a part of its One-Time Inspection Program and will be conducted in accordance with the requirements of ASME Code Section XI and 10 CFR Part 50, Appendix B.

The staff reviewed the applicant's One-Time Inspection Program, Systems Monitoring Program, and Water Chemistry Control Program and its evaluation is documented in SER Sections 3.0.3.2.13, 3.0.3.3.2, and 3.0.3.2.20, respectively.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.2 for further evaluation. For those line items that apply to LRA Section 3.2.2.2.2, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.3 Local Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.2.2.2.3 against the criteria in SRP-LR Section 3.2.2.2.3.

In LRA Section 3.2.2.2.3.2, the applicant addressed local loss of material from pitting and crevice corrosion. LRA Table 3.2.1, Item 3.2.1-05 and LRA Section 3.2.2.2.3.2 are also used for managing general corrosion and MIC.

SRP-LR Section 3.2.2.2.3.1 states that the existing aging management program relies on monitoring and control of primary water chemistry based on the guidelines presented in EPRI TR-105714 for PWRs 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 Water 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 confirm the effectiveness of the Water 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 LRA Section 3.2.2.2.3.1, the applicant stated that SRP-LR Section 3.2.2.2.3.1 is applicable to BWRs only.

SRP-LR Section 3.2.2.2.3.2 states that local loss of material from pitting and crevice corrosion could occur in the containment spray components, containment isolation valves and associated piping, and the buried portion of the refueling water tank external surface. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed consistent with the acceptance criteria as described in Branch Technical Position RSLB 1 (NUREG-1800 Appendix A.1).

In LRA Table 3.2.1, Item 3.2.1-05, the applicant refers to LRA Section 3.2.2.2.3.2 for the plant-specific further evaluation. In LRA Section 3.2.2.2.3.2, the applicant stated that the refueling water storage tank (RWST) is located indoors, not buried, and not susceptible to a wetted environment and, therefore, is not subject to this aging effect/mechanism. The applicant also stated that pitting and crevice corrosion typically are managed by the Water Chemistry Control Program and the One-Time Inspection Program. In LRA Section 3.2.2.2.3.2, the applicant does not discuss or summarize the evaluation findings, nor does LRA Section 3.2.2.2.3.1 make reference to the applicability of SRP-LR Section 3.2.2.2.3.1.

As documented in the audit and review report, the applicant stated that the evaluation of whether the aging management programs specified adequately manage the effects of aging identified in the Table 3.X.1 line item that require further evaluation was performed and is described in LRA Appendix B and its supporting plant documents. The applicant stated that its Water Chemistry Control Program conforms to the guidelines in EPRI TR-105714, Revision 4, and EPRI TR-102134, Revision 5. The Water Chemistry Control Program mitigates aging effects such as loss of material due to general, pitting, and crevice corrosion, and MIC, by controlling the environment to which components and associated piping are exposed. This aging effect is minimized by controlling the chemical species that cause the underlying mechanisms that result in this aging effect. The program provides assurance that an elevated level of contaminants and oxygen does not exist and, therefore, minimizes the occurrences of this aging effect. The applicant stated that its Water Chemistry Control Program has been in effect since initial plant operation and has been effective at maintaining the desired system water chemistry and detecting abnormal conditions, which have been corrected in an expedient manner.

The applicant further stated that because water chemistry alone will not preclude the loss of material due to pitting and crevice corrosion, a one-time inspection of susceptible locations will be performed to confirm the effectiveness of the Water Chemistry Control Program. For general corrosion, the one-time inspections will monitor wall thickness and the examination methods will include visual (VT-3) and/or volumetric (RT/UT). For pitting and crevice corrosion, these one-time inspections will monitor wall thickness and the examination methods will include visual (VT-1) and/or volumetric (RT/UT). Visual inspections will be performed only when the components are drained or opened and the component surface of interest is accessible. If degradation is identified through a visual inspection, additional NDE may be performed to characterize the degradation and determine the extent of condition. The applicant stated that the NDE exams will be performed as a part of the One-Time Inspection Program and will be conducted in accordance with the requirements of ASME Code Section XI and 10 CFR Part 50, Appendix B.

The staff reviewed the applicant's Water Chemistry Control Program and One-Time Inspection Program, and its evaluations are documented in SER Sections 3.0.3.2.20 and 3.0.3.2.13, respectively.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.3 for further evaluation. For those line items that apply to LRA Section 3.2.2.2.3, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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.

In the LRA Section 3.2.2.2.4, the applicant addresses local loss of material due to MIC.

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.

In LRA Section 3.2.2.2.4, the applicant stated that although PBNP has components in the ESF that are subject to MIC, this line item was not used. The applicant stated that this internal environment is addressed in LRA Section 3.2.1, Item 3.2.1-05 for loss of material due to pitting and crevice corrosion, because detection and prevention of these aging effects/mechanisms would also detect and prevent MIC. In these cases, the LRA credited the Water Chemistry Control Program and the One-Time Inspection Program.

In its letter, dated July 12, 2004, the applicant stated that for MIC one-time inspections, the parameter monitored will be wall thickness and the examination methods will include visual (VT-3) and/or volumetric (RT/UT). Visual inspections will be performed only when the components are drained or opened and the component surface of interest is accessible. If degradation is identified through a visual inspection, additional NDE may be performed to characterize the degradation and determine the extent of condition.

The staff reviewed the applicant's Water Chemistry Control Program and One-Time Inspection Program, and its evaluation is documented in SER Sections 3.0.3.2.20 and 3.0.3.2.13, respectively.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.2.2.2.4 for further evaluation. For those line items that apply to LRA Section 3.2.2.2.4, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2.5 Changes in Material 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 stated that this aging effect applies to BWRs only.

SRP-LR Section 3.2.2.2.5 states that the changes in properties due to elastomer degradation could occur in seals associated with the standby gas treatment system ductwork and filters.

SRP-LR Table 3.2-1 states that the further evaluation for this aging effect in the standby gas treatment system seals is applicable to BWR plants only.

The staff found that this aging effect is not applicable to PBNP.

3.2.2.2.6 Local Loss of Material Due to Erosion

The staff reviewed LRA Section 3.2.2.2.6 against the criteria in SRP-LR Section 3.2.2.2.6.

In LRA Section 3.2.2.2.6, the applicant addressed local loss of material due to erosion that could occur in the high-pressure safety injection pump miniflow orifice.

SRP-LR Section 3.2.2.2.6 states that local loss of material due to erosion could occur in the high-pressure safety injection pump miniflow orifice. This aging mechanism and its effect applies only to pumps that are normally used as charging pumps in the chemical and volume control systems. The GALL Report recommends further evaluation to ensure that the aging effect is adequately managed consistent with the acceptance criteria as described in Branch Technical Position RSLB 1 (NUREG-1800, Appendix A.1).

LRA Table 3.2.1, Item 3.2.1-08 stated that this further recommended evaluation is not applicable at PBNP as safety injection pumps are not normally in use. Therefore, the applicant stated, in LRA Section 3.2.2.2.6, that loss of material due to erosion of miniflow orifices is not applicable to the facility.

As documented in the audit and review report, the applicant was asked to discuss its evaluation of erosion susceptibility in the residual heat removal pump miniflow orifice lines that justify either the absence of erosion or the aging management programs that will be relied on to manage the aging mechanism. In its letter dated July 12, 2004, the applicant stated that a review of the potential for loss of material due to cavitation has been completed and had concluded that erosion-cavitation could not be ruled out. The applicant stated that, as part of the 2005 annual LRA update, the downstream piping in the vicinity of the low head safety injection (residual heat removal) pump mini-flow orifices will be examined under the One-Time Inspection Program. The staff found that loss of material due to cavitation may not exist at PBNP; however, the implementation of the One-Time Inspection Program will validate whether the aging effect exists or not. The staff found this acceptable.

The staff found that, based on a review of the July 12, 2004 letter, the applicant has met the criteria of SRP-LR Section 3.2.2.2.6 for further evaluation. For those line items that apply to LRA Section 3.2.2.2.6, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 stated that this aging effect applies to BWRs only.

SRP-LR Section 3.2.2.2.7 states that the plugging of components due to general corrosion could occur in the spray nozzles and flow orifices of the drywell and suppression chamber spray system of BWRs.

The staff found that this aging effect is not applicable.

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 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).

3.2.2.3 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 3.2.2-4 the applicant provided additional details of the results of the AMRs for material, environment, aging effects requiring management, and AMP combinations that are not consistent with the GALL Report or are not addressed in the GALL Report.

As documented under RAI 2.1-1 in SER Section 2.1, by letter dated April 29, 2005, the applicant changed the methodology used to determine the nonsafety-related SCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). As a result of the implementation of the scoping methodology changes, the applicant identified changes to LRA Tables 3.2.2-1 and 3.2.2-2.

In LRA Tables 3.2.2-1 through 3.2.2-4, 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 it 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 will be maintained consistent with the CLB during the period of extended operation.

3.2.2.3.1 Engineered Safety Features Components That Have No Aging Effect - Tables 3.2.2-1 through 3.2.2-4

The applicant stated that there are no aging effects identified for several of the line items in LRA Table 3.2.2-1 through Table 3.2.2-4 for the following material and environment combinations: (1) carbon steel, low-alloy steel, stainless steel, and cast stainless steel component internal surfaces in contact with an air (defined as dehumidified atmospheric air, dry/filtered instrument air) and gas environment; (2) stainless steel, glass, and cast stainless steel component external surfaces exposed to an indoor air environment with no air conditioning; and (3) stainless steel, and cast stainless steel component external surfaces exposed to a containment air environment. The applicant described the above environment groups in LRA Tables 3.0-1 and 3.0-2.

In LRA Table 3.0-1, the applicant stated that component internal surfaces in an air and gas environment may be exposed to dehumidified atmospheric air, dry/filtered instrument air and nitrogen, hydrogen, helium, or halon inert gases. The staff considers this air and gas environment benign and that its contact with the carbon steel, low-alloy steel, stainless steel, and cast stainless steel surfaces will not result in aging effects in those components identified in LRA Table 3.2.2-1 through 3.2.2-4.

In LRA Table 3.0-2, the applicant described the indoor air environment with no air conditioning as moist air at an average temperature of 85 °F and maximum relative humidity of 100 percent. The external surfaces are not directly exposed to weather, and the environment may be climate-controlled (heating and/or cooling), which may not prevent local condensation. The staff found that the stainless steel and cast stainless steel surfaces in contact with this indoor air environment will not result in aging effects in those components identified in LRA Tables 3.2.2-1 through 3.2.2-4.

In LRA Table 3.0-2, the applicant also stated that the containment air temperature in generally accessible areas is 50 °F to 105 °F and can be as high as 135 °F to 150 °F in some specific locations. The maximum relative humidity could reach 100 percent. The applicant stated that the nominal 40-year radiation dose is estimated to be 5.8E+7 rads. The staff found that, for those components identified in LRA Tables 3.2.2-1 through 3.2.2-4, stainless steel, glass, and cast stainless steel component external surfaces in contact with the containment environment will not result in any significant aging effects. Because the stainless steel and cast stainless steel components are not subjected to high fast neutron flux, irradiation embrittlement for these components is not a concern. Ionization due to gamma rays or to beta and alpha particle radiation has little effect on metals. Also, because the containment temperatures are low, thermal aging embrittlement of cast stainless steel components is not applicable.

On the basis of its review of current industry research and operating experience, the staff found that dry air on metal will not result in aging that will be of concern during the period of extended operation. Stainless steel and nickel-based alloy components in air or an inert gas environment are not susceptible to general corrosion that would affect their intended function. Therefore, the staff concluded that there are no applicable aging effects requiring management for carbon steel, stainless steel or stainless steel clad components exposed to air, or to an inert gas environment.

3.2.2.3.2 Safety Injection System - Aging Management Evaluation - Table 3.2.2-1

The staff reviewed LRA Table 3.2.2-1, as modified by letter dated April 29, 2005, which summarizes the results of AMR evaluations for the safety injection system component groups.

The safety injection system experiences loss of material of carbon and low-alloy steel, cast iron, stainless steel, and CASS for the following component types:

- level gauges
- heat exchanger
- instrument valve assemblies
- level elements
- piping and fittings
- pump casings
- restricting orifices
- tanks
- valve bodies
- flow elements

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- containment (external)
- treated water - borated (T<140 °F)(internal)
- indoor - no air conditioning (external)
- treated water - other (stagnant)(internal)
- treated water - borated (T>140 °F)(internal)
- air and gas (internal)

The applicant proposed to manage the safety injection system components loss of material aging effects by using the Bolting Integrity Program, Boric Acid Corrosion Program, Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program, Systems Monitoring Program and Water Chemistry Control Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.4, 3.0.3.2.6, 3.0.3.2.9, 3.0.3.2.13, 3.0.3.3.2, and 3.0.3.2.20, respectively.

The staff's review of LRA Section 3.2 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.

RAI 3.2-1. In LRA Tables 3.2.2-1, 3.2.2-2, and 3.2.2-3, stainless steel heat exchangers with heat transfer as the intended function are identified with only internal environments and associated aging effects. The external environment is listed as "not applicable." In RAI 3.2-1, dated July 30, 2004, the staff requested the applicant to explain why no external environments and associated aging effects are identified. The staff also requested the applicant to address the similar issue for the stainless steel heat exchangers in LRA Tables 3.2.2-1 and 3.2.2-2, which have pressure boundary as their intended function.

In its response, dated August 30, 2004, the applicant stated that, due to the way the license renewal database was developed and used, tubing assets were identified as two separate components (tubing ID and tubing OD). This allowed the user to designate an internal environment for each (tubing ID and tubing OD), but since the database required each component to have both an internal and external environment, the external environment would then be documented as "N/A." The applicant notes that in LRA Tables 3.2.2-1, 3.2.2-2, and 3.2.2-3, there is a heat exchanger material type with two different internal environments, which is reflective of the environments for the ID and OD of the tubing. Because the tubing has a pressure boundary intended function in addition to the heat transfer function, the same information was duplicated for the pressure boundary intended function line items.

The applicant stated that the only components that have a heat transfer intended function are the tubes. The heat exchanger shell has as its only intended function pressure boundary. External environments (indoor - no air conditioning, outdoor, etc.) would, therefore, only apply to the shell. Additionally, the shell is typically made of a different material than the tubes and, therefore, would not be represented by the same line item as the tubing in the LRA.

The staff considers the applicant's response to be adequate in explaining the relationship among components, material, and environments listed in the above tables. The staff's concern described in RAI 3.2-1 is resolved and the response is, therefore, acceptable.

RAI 3.2-2. In LRA Tables 3.2.2-1 and 3.2.2-2, carbon/low-alloy steel tanks are identified with only external environments and the associated aging effect. The internal environment is listed as "not applicable." On the other hand, stainless steel tanks are identified with internal environments and associated aging effects. In RAI 3.2-2, dated July 30, 2004, the staff requested the applicant to explain what material of construction for the tank is used, and the environments to which it is exposed, to support the information provided in the above tables.

In its response, dated August 30, 2004, the applicant stated that the issue was identified due to having carbon/low-alloy steel tanks that are clad with stainless steel. Due to the design of the license renewal database, each component can only have one material. However, there are two separate assets to describe the tanks. One asset would be the carbon/low-alloy steel shell, which is subject to an external environment, with internal environment being "N/A." Similarly, the stainless steel cladding has an internal environment, but the external environment is "N/A."

The staff considers the applicant's response to be adequate in explaining the relationship between the materials of construction and the associated environments for the tanks. The staff's concern described in RAI 3.2-2 is resolved and the response is, therefore, acceptable.

On the basis of its review of the applicant's plant-specific and industry operating experience, and the above discussion, the staff found that loss of material of carbon and low-alloy steel, cast iron, stainless steel, and CASS materials for component types in the safety injection system are effectively managed using the Bolting Integrity Program, Boric Acid Corrosion Program, Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program, Systems Monitoring Program and Water Chemistry Control Program. On this basis, the staff found that management of loss of material in the safety injection system components using these programs is acceptable.

The applicant proposed to manage loss of heat transfer due to fouling of stainless steel in heat exchangers exposed to treated water - borated (T<140 °F)(internal), and treated water - other (stagnant)(internal) using the Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program, and Water Chemistry Control Program.

The staff reviewed the applicant's Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program, and Water Chemistry Control Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.9, 3.0.3.2.13, and 3.0.3.2.20, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of heat transfer of stainless steel material for component types in the safety injection system is effectively managed using the Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program, and Water Chemistry Control Program. Therefore, the staff found that management of loss of heat transfer in the safety injection system components using these programs is acceptable.

3.2.2.3.3 Containment Spray - Aging Management Evaluation - Table 3.2.2-2

The staff reviewed LRA Table 3.2.2-2, as modified by letter dated April 29, 2005, which summarized the results of AMR evaluations for the containment spray system component groups.

The containment spray system experiences loss of material of carbon and low-alloy steel, stainless steel, cast iron and CASS materials for the following component types:

- eductor
- flow elements
- heat exchangers
- instrument valve assemblies
- piping and fittings
- pump casings
- restricting orifices
- tanks
- valve bodies
- level gauges

For those components requiring staff review, the environments are listed below:

- treated water - borated (T<140 °F)(internal)
- indoor - no air conditioning (external)
- treated water - other (stagnant)(internal)
- containment (external)
- borated water leaks (external)

The applicant proposed to manage the containment spray system components' loss of material aging effects by using the Bolting Integrity Program, Boric Acid Corrosion Program, Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program, Systems Monitoring Program and Water Chemistry Control Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.4, 3.0.3.2.6, 3.0.3.2.9, 3.0.3.2.13, 3.0.3.3.2, and 3.0.3.2.20, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material of carbon and low-alloy steel, stainless steel, cast iron and CASS materials for component types in the containment spray system components are effectively managed using the Bolting Integrity Program, Boric Acid Corrosion Program, Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program, Systems Monitoring Program and Water Chemistry Control Program. Therefore, the staff found that management of loss of material in the containment spray system components using these programs is acceptable.

The applicant proposed to manage loss of heat transfer due to fouling of stainless steel material for heat exchangers in the containment spray system exposed to treated water - borated (T<140 °F)(internal) and stagnant treated water using the Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program, and the Water Chemistry Control Program.

The staff reviewed the applicant's Closed-Cycle Cooling Water System Surveillance Program, One-time Inspection Program and Water Chemistry Control Program. The staff's evaluations of these programs is documented in SER Sections 3.0.3.2.9, 3.0.3.2.13, and 3.0.3.2.20, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of heat transfer of stainless steel for component types in the containment spray system components is effectively managed using the Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program and Water Chemistry Control Program. Therefore, the staff found that management of heat transfer in the containment spray system components using these programs is acceptable.

3.2.2.3.4 Residual Heat Removal - Aging Management Evaluation - Table 3.2.2-3

The staff reviewed LRA Table 3.2.2-3, which summarized the results of AMR evaluations for the residual heat removal system component groups.

The residual heat removal system experiences loss of material of carbon and low-alloy steel, stainless steel, cast iron, and CASS for the following component types:

- filters and strainers
- flow elements
- heat exchangers
- instrument valve assemblies
- piping and fittings
- pump casings
- restricting orifices
- sump screens
- tanks
- thermowells
- valve bodies
- valve operator

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- containment (external)
- treated water - borated (T<140 °F)(internal)
- indoor - no air conditioning (external)
- treated water - other (stagnant)(internal)

- treated water - borated (T>140 °F)
- air and gas - wetted (T<140 °F)(internal)
- oil and fuel oil (internal)

The applicant proposed to manage the residual heat removal system components' loss of material aging effects by using the Bolting Integrity Program, Boric Acid Corrosion Program, One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program, Systems Monitoring Program, Closed-Cycle Cooling Water System Surveillance Program, and Water Chemistry Control Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.4, 3.0.3.2.6, 3.0.3.2.13, 3.0.3.3.1, 3.0.3.3.2, 3.0.3.2.9, and 3.0.3.2.20, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material of carbon and low-alloy steel, stainless steel, cast iron, and CASS for component types in the residual heat removal system is effectively managed using the Bolting Integrity Program, Boric Acid Corrosion Program, One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program, Systems Monitoring Program, Closed-Cycle Cooling Water System Surveillance Program, and Water Chemistry Control Program. Therefore, the staff found that management of loss of material in the residual heat removal system components using these programs is acceptable.

The applicant proposed to manage loss of heat transfer due to fouling of stainless steel material for heat exchangers in the residual heat removal system exposed to borated treated (T<140 °F)(internal) and stagnant treated water using the Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program, and Water Chemistry Control Program. Also, the applicant proposed to manage cracking in stainless steel component types of piping and fittings by using the One-Time Inspection Program and Water Chemistry Control Program.

The staff reviewed the applicant's Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program and Water Chemistry Control Program. The staff's evaluations of these programs are addressed in SER Sections 3.0.3.2.9, 3.0.3.2.13, and 3.0.3.2.20, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of heat transfer and cracking of stainless steel for component types in the residual heat removal system components are effectively managed using the Closed-Cycle Cooling Water System Surveillance Program, One-Time Inspection Program and Water Chemistry Control Program. Therefore, the staff found that management of heat transfer in the residual heat removal system components using these programs is acceptable.

3.2.2.3.5 Containment Isolation Components System - Aging Management Evaluation - Table 3.2.2-4

The staff reviewed LRA Table 3.2.2-4, which summarized the results of AMR evaluations for the containment isolation components system.

The containment isolation components system experiences loss of material of carbon and low-alloy steel, stainless steel, and CASS for the following component types:

- CS components
- fasteners and bolting
- piping and fittings
- valve bodies

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- containment (external)
- indoor - no air conditioning (external)
- treated water - other (stagnant)(internal)

The applicant proposed to manage containment isolation components system components aging effects by using the Bolting Integrity Program, Boric Acid Corrosion Program, One-Time Inspection Program, Systems Monitoring Program and Water Chemistry Control Program. The staff's evaluation of these programs is documented in SER Sections 3.0.3.2.4, 3.0.3.2.6, 3.0.3.2.13, 3.0.3.3.2, and 3.0.3.2.20, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material of carbon and low-alloy steel, stainless steel, and CASS materials for component types in the containment isolation components system is effectively managed using the Bolting Integrity Program, Boric Acid Corrosion Program, One-Time Inspection Program, Systems Monitoring Program and Water Chemistry Control Program. Therefore, the staff found that management of loss of material in the containment isolation components system using these programs is acceptable.

All AMRs in LRA Tables 3.2.2-1 through 3.2.2-4 were evaluated. The staff found them to be acceptable.

Conclusion. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving material, environment, aging effect requiring management, and AMP 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.3 Conclusion

On the basis of its review, the staff concluded that the applicant has demonstrated that the aging effects associated with the engineered safety features components will be adequately managed so that the intended functions will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable FSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the ESF as required by 10 CFR 54.21(d).

3.3 Aging Management of Auxiliary Systems

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:

- chemical and volume control system
- component cooling water system
- spent fuel cooling system
- waste disposal system
- service water system
- fire protection system
- heating steam system
- emergency power system
- containment ventilation system
- essential ventilation system
- treated water system
- circulating water system
- fuel handling system
- plant sampling system
- plant air system
- containment hydrogen detectors and recombiner system

3.3.1 Summary of Technical Information in the Application

In LRA Section 3.3, the applicant provided AMR results for auxiliary systems components and component groups. In LRA Table 3.3.1, "Summary of Aging Management Evaluations in Chapter VII of NUREG-1801 for Auxiliary Systems," 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 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 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.

3.3.2 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 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).

Also, the staff performed an onsite audit 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 AMPs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluations are documented in the staff's PBNP audit and review report and summarized in SER Section 3.3.2.1.

The staff also performed an onsite audit of those AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff verified that the applicant's further evaluations were consistent with the acceptance criteria in NUREG-1800 Section 3.3.2.2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated July 2001. The staff's audit evaluations are documented in the staff's PBNP audit and review report and summarized in SER Section 3.3.2.2.

The staff performed an onsite audit and 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 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 staff's PBNP audit and review report and 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 FSAR supplement to ensure that they provide an adequate description of the programs credited with managing or monitoring aging for the auxiliary system 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 System 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 3.3.1-01)	Loss of material due to general, pitting, and crevice corrosion	Water chemistry and one-time inspection	Water 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 3.3.1-02)	Hardening, cracking and loss of strength due to elastomer degradation; loss of material due to wear	Plant-specific	Periodic Surveillance and Preventive Maintenance Program	Consistent with GALL, which recommends further evaluation. (See Section 3.3.2.2.2)
Components in load handling, chemical and volume control system (Item Number 3.3.1-03)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue (See Section 3.3.2.2.3)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
High-pressure pumps in chemical and volume control system (Item Number 3.3.1-04)	Crack initiation and growth due to SCC or cracking	Plant-specific	Water Chemistry Control Program; One-Time Inspection Program	Consistent with GALL, which recommends further evaluation. (See Section 3.3.2.2.4)
Components in ventilation system, diesel fuel oil system, and emergency diesel generator systems; external surfaces of carbon steel components (Item Number 3.3.1-05)	Loss of material due to general, pitting, and crevice corrosion, and MIC	Plant-specific	Periodic Surveillance and Preventive Maintenance Program; Open-Cycle Cooling (Service) Water System Surveillance Program; One-Time Inspection Program; Fire Protection Program; Tank Internal Inspection Program; Systems Monitoring Program	Consistent with GALL, which recommends further evaluation. (See Section 3.3.2.2.5)
Components in reactor coolant pump oil collection system of fire protection (Item Number 3.3.1-06)	Loss of material due to galvanic, general, pitting, and crevice corrosion	One-time inspection	One-Time Inspection Program	Consistent with GALL, which recommends further evaluation. (See Section 3.3.2.2.6)
Diesel fuel oil tanks in diesel fuel oil system and emergency diesel generator system (Item Number 3.3.1-07)	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Fuel oil chemistry and one-time inspection	Fuel Oil Chemistry Control Program; One-Time Inspection Program	Consistent with GALL, which recommends further evaluation. (See Section 3.3.2.2.7)
Heat exchangers in chemical and volume control system (Item Number 3.3.1-09)	Crack initiation and growth due to SCC and cyclic loading	Water chemistry and a plant-specific verification program	Water Chemistry Control Program; Closed Cycle Cooling Water System Surveillance Program; One-Time Inspection Program	Consistent with GALL, which recommends further evaluation. (See Section 3.3.2.2.9)
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	Not Applicable	Not Applicable (See Section 3.3.2.2.10)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
New fuel rack assembly (Item Number 3.3.1-11)	Loss of material due to general, pitting, and crevice corrosion	Structures monitoring	Structures Monitoring Program	Consistent with GALL, which recommends 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	Boraflex Monitoring Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.3.2.1)
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	Water chemistry	Water Chemistry Control Program; One-Time Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.3.2.1)
Closure bolting and external surfaces of carbon steel and low-alloy steel components (Item Number 3.3.1-14)	Loss of material due to boric acid corrosion	Boric acid corrosion	Boric Acid Corrosion Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.3.2.1)
Components in or serviced by closed cycle cooling waster system (Item Number 3.3.1-15)	Loss of material due to general, pitting, and crevice corrosion, and MIC	Closed-cycle cooling water system	Closed-Cycle Cooling Water System Surveillance Program; One-Time Inspection Program	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	Structures Monitoring Program; TLAA	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 (Service) Water System Surveillance Program; Periodic Surveillance and Preventive Maintenance Program; One-Time Inspection Program; Closed-Cycle Cooling Water System Surveillance 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
Buried piping and fittings (Item Number 3.3.1-18)	Loss of material due to general, pitting, and crevice corrosion, and MIC	Buried piping and tanks surveillance or Buried piping and tanks inspection	Buried Services Monitoring Program	Consistent with GALL, which recommends further evaluation. (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	Periodic Surveillance and Preventive Maintenance 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 protection (Item Number 3.3.1-20	Loss of material due to wear; hardening and shrinkage due to weathering	Fire protection	Fire Protection Program	Consistent with GALL, 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 Protection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.3.2.1)
Components in diesel fire system (Item Number 3.3.1-22)	Loss of material due to galvanic, general, pitting, and crevice corrosion	Fire protection and fuel oil chemistry	Fuel Oil Chemistry Control Program; Fire Protection Program	Consistent with GALL, 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	Systems Monitoring Program	Consistent with GALL, 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	Bolting Integrity 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 (aluminum bronze, brass, cast iron, cast steel) in open cycle cooling water and closed cycle cooling water systems, and ultimate heat sink (Item Number 3.3.1-29)	Loss of material due to selective leaching	Selective leaching of materials	Open-Cycle Cooling (Service) Water System Surveillance Program; Closed-Cycle Cooling Water System Surveillance Program; One-Time Inspection Program; Buried Services Monitoring Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.3.2.1)
Fire barriers, walls, ceilings, and floors in fire protection (Item Number 3.3.1-30)	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 and structures monitoring	Fire Protection Program; Structures Monitoring Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.3.2.1)

The staff's review of the PBNP auxiliary systems and associated components 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 the GALL Report or are 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
- Boric Acid Corrosion Program
- Closed-Cycle Cooling Water System Surveillance Program
- One-Time Inspection Program
- Systems Monitoring Program
- Water Chemistry Control Program
- Open-Cycle Cooling (Service) Water System Surveillance Program

- Periodic Surveillance and Preventive Maintenance Program
- Buried Services Monitoring Program
- Fire Protection Program
- Fuel Oil Chemistry Control Program
- Tank Internal Inspection Program

Staff Evaluation. In LRA Tables 3.3.2-1 through 3.3.2-16, the applicant provided a summary of AMRs for chemical and volume control system, component cooling water system, spent fuel cooling system, waste disposal system, service water system, fire protection system, heating steam system, emergency power system, containment ventilation system, essential ventilation system, treated water system, circulating water system, fuel handling system, plant sampling system, plant air system, and containment hydrogen detectors and recombiner system, 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 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's audit of those AMRs with Notes A through E, 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, although different, is 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, although different, is 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 its PBNP 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 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 had been reviewed and are 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 (Table 1), the applicant's references to the GALL Report are acceptable and no further staff review is required.

Conclusion. The staff verified 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 found 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 found 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).

3.3.2.2 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 provides further evaluation of aging management as recommended by the GALL Report for 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
- crack 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 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 3.3.3.2. Details of the staff's audit and review are documented in the staff's PBNP audit and review report. The staff's evaluation is discussed below.

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 loss of material in components of the spent fuel pool 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 tube sheets of the heat exchanger in the spent fuel pool cooling and cleanup system. For these components, made of carbon steel with elastomer lining, the GALL Report Table VII.A3 recommends managing the aging effects with a combination of the GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M32, "One-Time Inspection."

The applicant stated that NUREG-1801, Volume 2, items identified in Item 3.3.1-01 (A3.2-a, A3.3-a, and A3.5-a) relate to carbon steel components with elastomer linings. The applicant's spent fuel cooling system does not contain any carbon steel components with elastomer linings. All of the components in the spent fuel cooling system are stainless steel. The applicant further stated that, due to the absence of this material/environment combination in the auxiliary systems section, the applicant used LRA Table 3.2.1, Item 3.2.1-15 (ESF) to address aging effects of these components. The Water Chemistry Control Program is credited with managing these aging effects. The One-Time Inspection Program is also used to verify the effectiveness of water chemistry control.

The staff confirmed that these components are made of stainless steel and found that the applicant need not implement the further evaluation as defined in SRP-LR Section 3.3.2.2.1. The staff reviewed the applicant's Water Chemistry Control Program and One-time Inspection

Program and its evaluation is documented in SER Sections 3.0.3.2.20 and 3.0.3.2.13, respectively. Therefore, the staff found that the use of the Water Chemistry Control Program and One-Time Inspection Program are appropriate programs to manage the loss of material due to general, pitting, and crevice corrosion in the channel head and access cover, tubes, and tube sheets of the heat exchanger in the spent fuel pool cooling and cleanup system.

The staff found that, based on the programs identified above, the applicant had appropriately addressed the SRP-LR Section 3.3.2.2.1 further evaluation. For those line items that apply to LRA Section 3.3.2.2.1, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 Section 3.3.2.2.2.

In LRA Section 3.3.2.2.2, the applicant addressed 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, as well as 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.

The applicant stated that the spent fuel cooling system contains no components that are elastomer lined; however, the elastomer seals for the spent fuel pool gates are included in the LRA. The Periodic Surveillance and Preventive Maintenance Program is credited for managing the hardening and cracking. For ventilation systems, the applicant also credited the Periodic Surveillance and Preventive Maintenance Program for managing the hardening and cracking or loss of strength aging effects, where applicable. In many cases, the temperature, radiation, and ultraviolet exposure do not support these aging effects; therefore, no aging management is required.

The staff reviewed the applicant's Periodic Surveillance and Preventive Maintenance Program and its evaluation is documented in SER 3.0.3.3.1. On the basis of its review discussed in that section, the staff found that this program is appropriate to manage the hardening and cracking or loss of strength aging effects.

During the audit, the staff was concerned that many of the identified elastomer or nonmetallic components, as stated in LRA Note 16, are in areas where the temperatures in the identified environment may exceed the 95 °F threshold established by industry. In addition, the staff questioned the possibility of aging to occur to those neoprene components exposed to a raw water environment, which is not addressed in NUREG-1801.

The applicant stated that no aging effects exist for this material in these environments and that this is substantiated by plant-specific operating experience. LRA Note 16, for a particular component, stated that elastomer components are indoors and not subject to ultraviolet light or ozone, and they are not in locations that are subject to radiation exposure. These locations also are not subject to temperatures greater than 95 °F where change in material properties or cracking could occur; therefore, no aging management is required. Although LRA Table 3.0-2 stated that the indoor air, with no air conditioning, environment may achieve temperature variations between 70 °F to 120 °F with 100 percent humidity, this is provided as a generic environment, whereas LRA Note 16 is a specific environment for this material at a set location. These components were evaluated individually for both an internal raw water and external plant indoor, with no air conditioning, environment with regard to these criteria and, as a result, either were managed due to the potential for applicable effects/mechanisms for these environments or noted as not applicable where these criteria did not apply.

The staff reviewed the information provided by the applicant, as documented in its PBNP audit and review report, the staff found that the applicant had completed an individual assessment for each of the elastomer/nonmetallic components. All of these components in the auxiliary systems are in environments where aging is not expected to occur; therefore, the staff agreed that no AMP is required.

The staff found that, based on the program identified above, the applicant met the criteria of SRP-LR Section 3.3.2.2.2 for further evaluation. For those line items that apply to LRA Section 3.3.2.2.2, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 4.3 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 Section 3.3.2.2.4.

In LRA Section 3.3.2.2.4, the applicant addressed the potential for cracking in the high-pressure pumps of the chemical and volume control system.

SRP-LR Section 3.3.2.2.4 addresses crack initiation and growth due to cracking in the high pressure pump for the chemical and volume control system. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

The applicant stated that, although the GALL Report references a threshold temperature gate of less than 90 °C (200 °F) and a single aging effect, materials science supports: (1) a threshold temperature gate of greater than 140 °F for cracking due to SCC and (2) loss of material due to pitting and crevice corrosion for all temperatures. The applicant further stated that although the aging effect identified for temperatures less than 140 °F differs from that of the GALL Report, the Water Chemistry Control Program, which is credited for managing the aging effects for all temperatures, will preclude the possibility of cracking due to SCC. A One-Time Inspection Program is also credited to confirm the adequacy of water chemistry control.

The staff reviewed the applicant's Water Chemistry Control Program and One-Time Inspection Program and its evaluation is documented in SER Sections 3.0.3.2.20 and Section 3.0.3.2.13, respectively. The staff found the applicant's use of the Water Chemistry Control Program, which is credited for managing the aging effect of crack initiation and growth due to cracking or stress corrosion cracking, to be consistent with the GALL Report. The staff also found that the applicant's use of the One-Time Inspection Program to supplement the Water Chemistry Control Program is an additional measure to the GALL Report that will ensure identification of aging, should it occur in all areas, including those subject to stagnant flow conditions.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.3.2.2.4 for further evaluation. For those line items that apply to LRA Section 3.3.2.2.4, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21a)(3).

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 Section 3.3.2.2.5.

In LRA Section 3.3.2.2.5, the applicant addressed the loss of material due to general, microbiologically influenced, pitting, and crevice corrosion.

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, in the piping of the diesel generator building ventilation system, in 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 emergency diesel generator 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 material due to pitting and crevice corrosion could occur in the heating/cooling coils of the air handler heating/cooling, and 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 stated that (1) for the internal environments of applicable auxiliary systems, the Periodic Surveillance and Preventive Maintenance Program, Open-Cycle Cooling (Service) Water System Surveillance Program, One-Time Inspection Program, Fire Protection Program, and Tank Internal Inspection Program are credited for managing these aging effects; and (2) for the external surfaces of all carbon steel components in auxiliary systems, the Systems Monitoring Program or Bolting Integrity Program are credited for managing the aging effect of loss of material. Also, in some cases, the applicant credited the Open-Cycle Cooling (Service) Water System Surveillance Program or Fire Protection Program to augment the Systems Monitoring Program for managing external aging effects. Closure bolting associated with these components is addressed in LRA Table 3.3-1, Item 3.3.1-24.

As documented in the audit and review report, the applicant stated that this LRA section deals with the management of loss of material due to general, pitting, and crevice corrosion, and MIC for internal surfaces within ventilation and emergency power systems and for external surfaces of carbon steel component in auxiliary systems. The internal environments associated with this line item are those in which the internal surfaces are subject to normal atmospheric air and are also prone to wetting or condensation. The Periodic Surveillance and Preventive Maintenance Program provides for inspections of these wetted internal surfaces, which will look for and be able to detect this aging effect. The Tank Internal Inspection Program also provides for the inspection of selected tank internals, which will look for and be able to detect this aging effect; therefore, application of the Periodic Surveillance and Preventive Maintenance Program or the Tank Internal Inspection Program provides adequate assurance that this aging effect will be managed throughout the period of extended operation.

The Systems Monitoring Program provides for visual inspections and monitoring of external surfaces of piping, tanks, and other components and equipment, for leakage and evidence of material degradation. These inspections and monitoring identify the aging effect of concern (loss of material) on external surfaces prior to a loss of intended function of these components. The Open-Cycle Cooling (Service) Water System Surveillance Program and the Fire Protection Program provide for wall thickness assessments to be performed. These wall thickness assessments are typically performed from the outside of the components and, therefore, are capable of detecting any external surface degradation. On this basis, these two programs augment the Systems Monitoring Program for managing loss of material on the external surfaces of components within the service water system and the fire protection system.

The Bolting Integrity Program provides for visual inspection and monitoring of fasteners and bolting for loss of material. These inspections and monitoring identify loss of material on the external surfaces of these items prior to a loss of intended function of these items. Therefore, the Systems Monitoring Program, augmented in selected cases by the Open-Cycle Cooling (Service) Water System Surveillance Program, the Fire Protection Program, or the Bolting Integrity Program, provides adequate assurance that loss of material on the external surfaces of components will be managed for the period of extended operation.

The staff reviewed the applicant's Periodic Surveillance and Preventive Maintenance Program, Open-Cycle Cooling (Service) Water System Surveillance Program, One-Time Inspection Program, Fire Protection Program, Bolting Integrity Program, and Tank Internal Inspection Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.3.1, 3.0.3.2.14, 3.0.3.2.13, 3.0.3.2.10, 3.0.3.2.4, and 3.0.3.3.3, respectively.

The staff found that, based on the programs identified above, the applicant met the criteria of SRP-LR Section 3.3.2.2.5 for further evaluation. For those line items that apply to LRA Section 3.3.2.2.5, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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

The staff reviewed LRA Section 3.3.2.2.6 against the criteria in SRP-LR Section 3.3.2.2.6.

In Section 3.3.2.2.6, the applicant addressed further evaluation of programs to manage loss of material in the reactor coolant pump oil collection system by crediting the One-Time Inspection Program.

SRP-LR Section 3.3.2.2.6 states that loss of material due to general, galvanic, pitting, and crevice corrosion could occur in tanks, piping, valve bodies, and tubing in the reactor coolant pump oil collection system in fire protection. The Fire Protection Program relies on a combination of visual and volumetric examinations in accordance with the guidelines of 10 CFR 50, Appendix R, and Branch Technical Position 9.5 1 to manage loss of material from corrosion. However, corrosion may occur at locations where water from washdowns may accumulate. Therefore, verification of the effectiveness of the 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, galvanic, pitting, and crevice corrosion to confirm the effectiveness of the program. A one-time inspection of the bottom half of the interior surface of the tank of the reactor coolant pump oil collection system 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 it credited the One-Time Inspection Program for managing the aging effects of components within the reactor coolant pump oil collection subsystem.

As documented in the audit and review report, the staff held technical discussions with the applicant. The applicant stated that loss of material due to general, galvanic, pitting, and crevice corrosion could occur in the reactor coolant pump oil collection subsystem. The One-Time Inspection Program, which is credited to manage this aging effect, addressed the potentially long incubation period for this aging effect and provides a means of confirming that this aging effect is either not occurring or progressing so slowly as to have negligible effect on the intended function(s) of the reactor coolant pump oil collection subsystem.

The staff reviewed the applicant's One-Time Inspection Program and its evaluation is documented in SER Section 3.0.3.2.13. On the basis of its review, the staff found that the One-Time Inspection Program adequately manages the aging effects of components within the reactor coolant pump oil collection subsystem.

The staff found that, based on the program identified above, the applicant met the criteria of SRP-LR Section 3.3.2.2.6 for further evaluation. For those line items that apply to LRA Section 3.3.2.2.6, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 Section 3.3.2.2.7.

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

SRP-LR Section 3.3.2.2.7 states that loss of material due to general, pitting, and crevice corrosion, microbiologically induced corrosion (MIC), and biofouling could occur in the internal surface of tanks in the diesel fuel oil system in the emergency diesel generator system. The existing AMP relies on the Fuel Oil Chemistry Control 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 Fuel Oil 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 confirm 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.

The AMPs recommended by the GALL Report are GALL AMP XI.M30, "Fuel Oil Chemistry," and GALL AMP XI.M32, "One-Time Inspection," for management of this aging effect.

The applicant stated that the Fuel Oil Chemistry Control Program is credited with managing the applicable aging effects in the fuel oil systems. The applicant further stated that the One-Time Inspection Program is also used to verify the adequacy of the Fuel Oil Chemistry Program in managing these aging effects.

During the audit, the staff held technical discussion with the applicant. The applicant stated that loss of material due to general, pitting and crevice corrosion, MIC, and biofouling could occur on the internal surfaces of fuel oil tanks. The Fuel Oil Chemistry Control Program mitigates and manages these aging effects on the internal surfaces of fuel oil storage tanks and associated components in systems that contain fuel oil. The program includes: (1) surveillance and monitoring procedures for maintaining fuel oil quality by controlling contaminants in accordance with applicable ASTM standards, (2) periodic draining of water from fuel oil tanks, (3) periodic or conditional visual inspections of internal surfaces or wall thickness measurements from external surfaces of fuel oil tanks, and (4) one-time inspections of a representative sample of components in systems that contain fuel oil.

The objective of the Fuel Oil Chemistry Control Program is to minimize the introduction and presence of contaminants in the plant's fuel oil system that could cause degradation of components in systems that contain fuel oil. A representative sample of components in systems that contain fuel oil will be inspected via the One-Time Inspection Program. The

One-Time Inspection Program addresses the potentially long incubation periods for these aging effects and provides a means of confirming that these aging effects are either not occurring or progressing so slowly as to have negligible effect on the intended function(s) of these components; therefore, a combination of the Fuel Oil Chemistry Control Program and One-Time Inspection Program is used to manage these aging effects.

The staff reviewed the applicant's Fuel Oil Chemistry Control Program and One-Time Inspection Program and its evaluations of these programs are documented in SER Sections 3.0.3.2.12 and 3.0.3.2.13, respectively. On the basis of its review, the staff found that these programs adequately manage the applicable aging effects in the fuel oil system.

The staff found that, based on the programs identified above, the applicant met the criteria of SRP-LR Section 3.3.2.2.7 for further evaluation. For those line items that apply to LRA Section 3.3.2.2.7, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 Crack Initiation and Growth Due to Stress Corrosion Cracking and Cyclic Loading

The staff reviewed LRA *Section* 3.3.2.2.9 *against the criteria in* SRP-LR *Section* 3.3.2.2.9.

In LRA Section 3.3.2.2.9, the applicant addresses further evaluation of programs to manage cracking in the chemical and volume control system to confirm the effectiveness of the Water Chemistry Control Program.

SRP-LR Section 3.3.2.2.9 states that crack initiation and growth due to SCC and cyclic loading could occur in the channel head and access cover, tube sheet, tubes, shell and access cover, and closure bolting of the regenerative heat exchanger and in the channel head and access cover, tube sheet, and tubes of the letdown heat exchanger in the chemical and volume control system. The Water Chemistry Control Program relies on monitoring and control of water chemistry based on the guidelines of EPRI TR-105714 for primary water chemistry to manage the effects of crack initiation and growth due to SCC and cyclic loading. Verification of the effectiveness of the Water Chemistry Control Program should be performed to ensure that crack initiation and growth are not occurring. The GALL Report recommends further evaluation to manage crack initiation and growth from SCC and cyclic loading for these systems to confirm the effectiveness of the Water Chemistry Control Program. A one-time inspection of select components and susceptible locations is an acceptable method to ensure that crack initiation and growth are not occurring and that the component's intended function will be maintained during the period of extended operation.

The applicant stated, in the LRA, that although the GALL Report references a temperature gate of less than 90 °C (200 °F) and a single aging effect, materials science supports: (1) a temperature gate greater than 140 °F for cracking due to SCC and (2) loss of material due to pitting and crevice corrosion for all temperatures. Although the aging effect identified for temperatures less than 140 °F differs from that of the GALL Report's Water Chemistry Control Program, which is credited for managing the aging effects for all temperatures, it will preclude the possibility of cracking due to SCC. In some cases the Closed-Cycle Cooling Water System Surveillance Program is credited, which includes water chemistry controls for closed-cycle cooling water. In all cases the One-Time Inspection Program is also credited to confirm the adequacy of water chemistry control.

The staff reviewed the applicant's Water Chemistry Control Program, Closed-Cycle Cooling Water System Surveillance Program, and One-Time Inspection Program and its evaluations of these programs are documented in SER Sections 3.0.3.2.20, 3.0.3.2.9, and 3.0.3.2.13, respectively. The staff found the applicant's use of the Water Chemistry Control Program, which is applicable to all temperature ranges, for managing the aging effect crack initiation and growth due to SCC and cyclic loading, to be consistent with the GALL Report. The staff found that the applicant's use of the One-Time Inspection Program to supplement the Water Chemistry Control Program is consistent with the GALL Report to ensure identification of aging, should it occur in all areas including those that might be subject to stagnant or low-flow conditions. The staff found that the applicant's use of the Closed-Cycle Cooling Water System Surveillance Program, which includes water chemistry controls for closed-cycle cooling water, is an additional measure that supplements the criteria of the GALL Report and is an acceptable addition to ensure management of aging effects in the closed-cycle cooling water system.

The staff found that, based on the programs identified above, the applicant met the criteria of SRP-LR Section 3.3.2.2.9 for further evaluation. For those line items that apply to LRA Section 3.3.2.2.9, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 Section 3.3.2.2.10.

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 pool. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

In LRA Section 3.3.2.2.10, the applicant stated that this specific material, Boral, is not used in the spent fuel pool for neutron absorption; therefore, an AMP is not required. However, line Item 3.3.1-12, dealing with Boraflex, is applicable. The staff's evaluations of the Boraflex Monitoring Program and the spent fuel storage rack boraflex TLAA are evaluated in SER Sections 3.0.3.2.5, and 4.6, respectively.

On the basis that this component is not part of the PBNP design, the staff found that this aging effect is not applicable.

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 Section 3.3.2.2.11.

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 open-cycle cooling water system (service water 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 AMP recommended by the GALL Report is GALL AMP XI.M34, "Buried Piping and Tanks Inspection."

The applicant stated that the Buried Services Monitoring Program is credited for managing these aging effects for buried components. The applicant also stated that external surfaces of buried components are visually examined during maintenance activities (inspections of opportunity). No evidence of age-related degradation has been detected from inspections performed to date.

In RAI B2.1.7-1, discussed in SER Section 3.0.3.2.7, the staff requested the applicant to explain how it ensures that all buried components are coated. In its letter, dated March 15, 2005, the applicant stated that its Buried Services Monitoring Program includes visual inspections of the external surfaces of buried carbon steel, cast iron, and low-alloy steel components that are within the scope of license renewal in the service water, fuel oil, and fire protection systems.

The applicant also stated that inspections of the service water, fuel oil, and fire protection systems will be performed based on plant operating experience and opportunities for inspection. In addition, a susceptible location in the fire protection system (*i.e.*, uncoated unwrapped piping) will be scheduled to be inspected once prior to the period of extended operation and at least every 10 years during the period of extended operation. The intent of these scheduled inspections is to ensure that buried components within the fire protection system are periodically inspected. Therefore, if an opportunity for inspection occurs prior to the scheduled inspection, such inspection can be credited for satisfying the scheduled inspection.

The applicant also stated that groundwater/lake water is analyzed periodically, and that analyses performed to date confirm that the water is non-aggressive.

The staff reviewed the applicant's Buried Services Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.7. The staff found that the facility's operating history confirms that the Buried Services Monitoring Program is adequately managing the aging effects associated with loss of material due to general, pitting, and crevice corrosion and MIC that could occur in the underground piping and fittings in the service water system, in the fire protection system, and in the diesel fuel oil system. The staff also found that the applicant has measures currently in place that will adequately identify any degradation to components due to these aging effects.

The staff found that, based on the program identified above, the applicant met the criteria of SRP-LR Section 3.3.2.2.11 for further evaluation. For those line items that apply to LRA Section 3.3.2.2.11, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 3.3.2-16, 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 are not addressed in the GALL Report.

As documented under RAI 2.1-1 in SER Section 2.1, by letter dated April 29, 2005, the applicant changed the methodology used to determine the nonsafety-related SCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). As a result of the implementation of the scoping methodology changes, the applicant identified changes to LRA Tables 3.3.3.2-1, 3.3.2-2, 3.3.2-3, 3.3.2-4, 3.3.2-10, and 3.3.2-14.

In Tables 3.3.2-1 through 3.3.2-16, the applicant indicated, via Notes F through J, that neither the identified component nor the material/environment combination is evaluated in the GALL Report and provided information concerning how the AERM will be managed.

Staff Evaluation. For component type material/environment combinations 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 will be maintained consistent with the CLB during the period of extended operation.

The staff's review of LRA Section 3.3 identified areas in which additional information was necessary to complete the review of the applicant's results. The applicant responded to the staff's general RAIs as discussed below.

RAI 3.3-1. In LRA Tables 3.3.2-3, 3.3.2-7, and 3.3.2-9, heat exchangers and heater/coolers with heat transfer as the intended function are identified with only internal environments and associated aging effects. The external environment is listed as "N/A." In RAI 3.3-1, dated

November 18, 2004, the staff requested the applicant to explain why the external environment and associated aging effects were not be identified for these components. The applicant was also requested to address the similar question for the heat exchangers and heater/coolers in LRA Tables 3.3.2-2, 3.3.2-3, 3.3.2-4, 3.3.2-5, 3.3.2-7, and 3.3.2-9 which have pressure boundary as their intended function.

In its response, dated January 7, 2005, the applicant stated:

> Due to the way our database was developed and used, tubing assets were identified as two separate components (tubing ID and tubing OD). This allowed us to select an internal environment for each (ID and OD), but since the database required each component to have both an internal and external environment, we would then document the external environment as N/A. This was done to keep internal and external environments somewhat standard (see PBNP LRA Table 3.0-1, Internal Service Environments and Table 3.0-2, External Service Environments). Note that in Tables 3.3.2-3, 3.2-7, and 3.3.2-9, you will find a Heat Exchanger (HX) material type with two different internal environments, which is reflective of the environments for the ID and OD of the tubing.
>
> The only components that have a 'heat transfer' intended function are the tubes. External environments (indoor - no air conditioning, outdoor, etc.) would only apply to the shell of the HX, and since the shell only has a pressure boundary function, it (the shell) and its external environment are not identified under the 'heat transfer' intended function. Additionally, the shell is typically made of a different material than the tubes and, therefore, would not be represented by the same line item as the tubing in the LRA.
>
> This same methodology was used for heat exchangers and heater/coolers that have 'pressure boundary' intended functions, which produces similar results in Tables 3.3.2-2, 3.3.2-3, 3.3.2-4, 3.3.2-5, 3.3.2-7, and 3.3.2-9.

The staff found the applicant's response acceptable. The applicant provided a satisfactory explanation for identifying the external environment and the associated aging effects for the various components requested. The staff's concern described in RAI 3.3-1 is resolved.

<u>RAI 3.3-2</u>. LRA Table 3.3.2-7 identifies no aging effects for neoprene expansion joints with an internal environment of air and wetted gas less than 140°F. Also, LRA Table 3.3.2-13 identifies the aging effects change in material properties and cracking for neoprene expansion joints with an external environment of indoor with no air conditioning; however, no aging management is performed for these components. For similar neoprene components in warm, moist environments, the GALL Report identifies two aging effects: hardening and loss of strength, and recommends a plant-specific AMP to manage these aging effects. In RAI 3.3-2, dated November 18, 2004, the staff requested the applicant to provide justification as to why no aging effects were identified for the internals of the expansion joints in LRA Table 3.3.2-7 and why no aging management is identified for the expansion joints in LRA Table 3.3.2-13.

In its response, dated January 7, 2005, the applicant stated:

> In accordance with the EPRI report 1002950, Aging Effects for Structures and Structural Components (Structural Tools), Revision 1, August 2003, no aging effects exist for this material in these environments and this is substantiated by PBNP plant-specific Operating Experience (OE). We attempted to explain this using Note 16 in Table 3.3.2.7. Note 16 states that elastomer (neoprene, rubber, etc.) components are indoors and not subject to Ultraviolet (UV) or ozone, nor are they in locations that are subject to radiation exposure. These locations are also not subject to temperatures where change in material properties or cracking could occur (*i.e.*, greater than 95 ºF).
>
> Although the environment definition implies that temperatures may reach 140 ºF, the actual individual environments for these specific components were reviewed, and they do not exceed the 95 ºF threshold temperature. As a result, it was determined that these criteria are not exceeded in these instances and, therefore, no aging management is required.

The staff found the applicant's response acceptable. The applicant explained why no aging effects were identified for certain expansion joints and no AMPs were provided for certain other expansion joints. The staff's concern described in RAI 3.3-2 is resolved.

RAI 3.3-5. LRA Tables 3.3.2-7 and 3.3.2-9 identify the Periodic Surveillance and Preventive Maintenance Program to manage loss of heat transfer due to fouling for heat exchangers in oil and fuel oil (internal), outdoor (external), and air and gas within wetted environments. The "monitoring and trending" program element states that inspections, examination, testing, and component replacement activities are performed on a specified frequency based on operating experience or other requirements. The applicant stated that the results of these surveillance and preventive maintenance activities are documented, and subject to review and approval. NUREG-1800 Section A.1.2.3.5 recommends that monitoring and trending activities be described, and they should provide predictability of the extent of degradation and thus effect timely corrective actions. Plant-specific and/or industry operating experience may be considered in evaluating the appropriateness of the technique and frequency. In RAI 3.3-5, dated November 18, 2004, the staff requested the applicant to describe the inspection technique and frequency. The inspection frequency should be justified by plant operating experience and should be adequate to detect the aging effects such that the intended function will be maintained during the period of extended operation.

In its response, dated January 7, 2005, the applicant stated:

> By letter dated February 25, 2004 (NRC 2004-0016), Nuclear Management Company (NMC), LLC, submitted the Point Beach Nuclear Plant (PBNP) Units 1 and 2 License Renewal Application (LRA). During the weeks of April 26 and June 7, 2004, the NRC performed an on-site audit of the PBNP aging management programs and aging management reviews. As a result of this audit and subsequent conversations between NMC and the NRC staff, the NRC staff requested various clarifications to the LRA. By letter dated July 12, 2004 (NRC 2004-0071), NMC submitted these LRA clarifications to the NRC staff. Several of these clarifications involved the Periodic Surveillance and

Preventive Maintenance Program (LRA Section B2.1.15), including the responses to Audit items 69, 148 and 196 in the enclosure to this letter.

The response to Audit item 196 provides a table that links the aging effects/ mechanisms managed by the Periodic Surveillance and Preventive Maintenance Program with the parameters monitored/inspected and the measurement methodology. The inspection method identified for loss of heat transfer due to fouling is General or Remote Visual. Where the material is in an oil or fuel oil environment, an oil sample will be taken and analyzed for evidence of MIC, corrosion products, and/or other contaminants in lieu of these inspection. General or remote visual examinations will be performed in accordance with the requirements of ASME Section V and 10 CFR 50, Appendix B. This inspection methodology is capable of measuring the parameter monitored (*i.e.*, tube fouling) and providing data that is adequate to conclude the aging effect is managed consistent with the current licensing basis. If a different inspection method is used, the basis for the revised inspection method will be documented. If degradation is identified through a visual inspection, additional non-destructive examination (NDE) may be performed to characterize the degradation and determine the extent of condition. The inspection frequency for the Periodic Surveillance and Preventive Maintenance Program activities credited for those line items in LRA Tables 3.3.2-7 and 3.3.2-9 will be justified by plant-specific operating experience during implementation of the program. This process will ensure that the activities will be adequate to detect aging effects such that the intended function will be maintained during the period of extended operation.

The staff found the applicant's response reasonable and acceptable. The applicant provided a satisfactory explanation of how the inspection technique and frequency would remain adequate to detect the aging effects. The staff's concern described in RAI 3.3-5 is resolved.

RAI 3.3-6. The loss of preload is an aging effect for closure bolting in high temperature or high pressure systems. GALL AMP XI.M18, "Bolting Integrity" program provides aging management inspections for this aging effect. LRA Section 3.3 for the auxiliary systems does not identify loss of preload as an aging effect for closure bolting. In RAI 3.3-6, dated November 18, 2004, the staff requested the applicant to discuss why the loss of preload was not identified as an aging effect for auxiliary systems closure bolting and the inspections in GALL AMP XI.M18 were not credited for managing this aging effect.

In its response, dated January 7, 2005, the applicant stated the following:

... NMC considered loss of preload for closure bolting to be a design driven effect, not an applicable aging effect for the Engineered Safety Features (ESF), Auxiliary Systems, and Steam and Power Conversion System (SPCS) system groupings. Operating temperatures in these three system groupings are below the threshold temperature where creep of the bolting material could occur. Additionally, a properly designed and installed bolted joint will not be affected by loss of preload. Leakage at joints is typically associated with improper joint installation (*e.g.*, proper cleanliness, gasketing, and preload) or inadequate joint design, not relaxation of the bolting materials. Although PBNP does not consider loss of preload an aging effect, normal maintenance practices intended to preclude loss of preload are applied to pressure-retaining bolted connections when they are assembled. These maintenance practices are proceduralized and include proper torque selection, torque patterns, thread engagement criteria, and inspection of bolting materials including gaskets. These procedures for joint installation incorporate industry bolting guidance, which also provide for the use of proper lubricants and sound bolt torquing practices. PBNP's plant-specific operating experience shows that bolted joint failures due to loss of preload are not occurring within these system groupings. Therefore, the loss of preload due to stress relaxation for closure bolting in the Auxiliary Systems, ESF, and SPCS system groupings does not require aging management based on system operating temperatures and industry bolting practices.

During a meeting on February 15, 2005, the staff indicated and the applicant agreed, that this response requires further clarification. The staff requested the applicant to provide technical justification for not managing loss of preload for all safety-related bolting or confirm that the Bolting Integrity Program applies good bolting practices to manage loss of mechanical closure integrity caused by loss of preload for all bolting within the scope of license renewal.

In its response, a clarification letter dated March 15, 2005, the applicant stated that the Bolting Integrity Program will manage loss of preload for bolted connections subject to vibration or high temperatures in the engineered safety features, auxiliary systems, and steam and power conversion systems.

The staff finds the applicant's response reasonable and acceptable. The applicant explained that loss of preload for applicable bolts will be managed by the Bolting Integrity Program. The staff's concern described in RAI 3.3-6 is resolved.

3.3.2.3.1 Auxiliary System Components That Have No Aging Effects - Tables 3.3.2-1 through 3.3.2-16

In LRA Tables 3.3.2-1 through 3.3.2-16, the applicant identified line items where no aging effects were identified as a result of the aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from carbon steel, copper alloy, stainless steel or stainless steel clad material, CASS and glass were exposed to air or to an inert gas. The applicant defined an air environment as dehumidified atmospheric air, dry/filtered instrument air. Neither air nor inert gas is identified in the GALL Report as an environment for these components and materials. No aging effects are considered to be applicable to carbon steel, copper alloy, stainless steel or stainless steel clad, CASS and glass components exposed to air, or to an inert gas environment.

On the basis of its review of current industry research and operating experience, the staff found that dry air on metal will not result in aging that will be of concern during the period of extended operation. Stainless steel and nickel-based alloy components in air or an inert gas environment are not susceptible to general corrosion that would affect their intended function. Therefore, the staff concluded that there are no applicable aging effects requiring management for carbon steel, copper alloy, stainless steel or stainless steel clad, CASS and glass components exposed to air, or to an inert gas environment.

3.3.2.3.2 Chemical and Volume Control System - Aging Management Evaluation - Table 3.3.2-1

The staff reviewed LRA Table 3.3.2-1, as modified by letter dated April 29, 2005, which summarizes the results of AMR evaluations for the chemical volume and control system component groups.

The chemical and volume control system experiences loss of material of carbon and low-alloy steel, stainless steel and CASS for the following component types:

- CS components
- fasteners and bolting
- filters and strainers
- flow elements
- heat exchangers
- level gauges
- instrument valve assemblies
- piping and fittings
- pump casings
- tanks
- thermowells
- valve bodies

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- containment (external)
- treated water - borated (T>140 °F)(internal)
- treated water - borated (T<140 °F)(internal)
- treated water - primary (T<140 °F)(internal)
- treated water - primary (140°F< T<480 °F)(internal)
- treated water - other (internal)
- treated water - other (stagnant)(internal)
- indoor - no air conditioning (external)

The staff evaluation with respect to component environments listed as "not applicable" and loss of preload for closure bolting are discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the chemical volume and control system loss of material aging effects by using the Boric Acid Corrosion Program, Bolting Integrity Program, One-Time Inspection Program, Water Chemistry Control Program, Systems Monitoring Program, and Closed-Cycle Cooling Water System Surveillance Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.6, 3.0.3.2.4, 3.0.3.2.13, 3.0.3.2.20, 3.0.3.3.2, and 3.0.3.2.9, respectively.

The applicant proposed to manage cracking due to SCC of stainless steel material for component types of heat exchanger, valve bodies, piping, and fitting, exposed to borated water and treated water with temperatures between 140 °F and 480 °F environment using the One-Time Inspection Program, and Water Chemistry Control Program.

The staff reviewed the applicant's One-Time Inspection Program and Water Chemistry Control Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.13 and 3.0.3.2.20, respectively. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that cracking due to SCC of stainless steel material for component types in the chemical and volume control system is effectively managed using the One-Time Inspection Program and Water Chemistry Control Program. Therefore, the staff found that management of cracking due to SCC in the chemical and volume control system using these programs is acceptable.

3.3.2.3.3 Component Cooling Water System - Aging Management Evaluation - Table 3.3.2-2

The staff reviewed LRA Table 3.3.2-2, as modified by letter dated April 29, 2005, which summarizes the results of AMR evaluations for the component cooling water system component groups.

The component cooling water system experiences loss of material of carbon and low-alloy steel, stainless steel, cast iron, copper alloy (Zn<15%) and copper alloy (Zn>15%) for the following component types:

- CS components
- fasteners and bolting
- flow elements
- heat exchangers
- radiation monitor
- instrument valve assemblies
- piping and fittings
- pump casings
- tanks
- thermowells
- valve bodies

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- treated water - other (velocity)(internal)
- raw water (velocity)(internal)
- treated water - primary (T>480 °F)(internal)
- treated water - primary (140°F<T<480 °F)(internal)
- treated water - secondary (T>120 °F)(internal)
- treated water - other (stagnant)(internal)
- air and gas - wetted (T<140 °F)(internal)
- containment (external)
- indoor - no air conditioning (external)

The staff evaluation with respect to component environments listed as "not applicable" and loss of preload for closure bolting are discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the component cooling water system loss of material aging effects by using the Boric Acid Corrosion Program, Bolting Integrity Program, One-Time Inspection Program, Water Chemistry Control Program, Systems Monitoring Program, Open-Cycle Cooling (Service) Water System Surveillance Program, and Closed-Cycle Cooling Water System Surveillance Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.6, 3.0.3.2.4, 3.0.3.2.13, 3.0.3.2.20, 3.0.3.3.2, 3.0.3.2.14, and 3.0.3.2.9, respectively.

On the basis of its review, the staff found the aging effects of the above component cooling water system components are consistent with industry experience for these combinations of materials and environments. The staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the component cooling water system.

The applicant proposed to manage loss of heat transfer due to fouling of stainless steel material for component type of heat exchanger exposed to treated water - other (velocity), and raw water (velocity) environment using the Open-Cycle Cooling (Service) Water System Surveillance Program and Closed-Cycle Cooling Water System Surveillance Program.

The staff reviewed the applicant's Open-Cycle Cooling (Service) Water System Surveillance Program and Closed-Cycle Cooling Water System Surveillance Program. The staff's evaluations are documented in SER Sections 3.0.3.2.14 and 3.0.3.2.9, respectively. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of heat transfer due to fouling for component types in the component cooling water system are effectively managed using the Open-Cycle Cooling (Service) Water System Surveillance Program and Closed-Cycle Cooling Water System Surveillance Program. Therefore, the staff found that management of loss of heat transfer due to fouling in the component cooling water system using these programs is acceptable.

The applicant proposed to manage cracking due to SCC, IGA, and IGSCC of stainless steel materials for component type of heat exchanger pressure boundaries exposed to primary treated water with temperature greater than 480 °F, with temperature between 140 °F and 480 °F, and secondary treated water with temperature greater than 120 °F environments using Water Chemistry Control Program and the One-Time Inspection Program.

The staff reviewed the applicant's Water Chemistry Control Program and One-Time Inspection Program and its evaluations are documented in SER Sections 3.0.3.2.20 and 3.0.3.2.13, respectively. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that cracking due to SCC for component types in the component cooling water system is effectively managed using the Water Chemistry Control Program and One-Time Inspection Program. On this basis, the staff found that management of cracking due to SCC in the component cooling water system is acceptable.

The staff's review of LRA Table 3.3.2-2 identified an area 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.

RAI 3.3-7. In LRA Table 3.3.2-2, the applicant proposed to manage cracking due to IGA/IGSCC of stainless steel material for heat exchanger components exposed to primary treated water with temperature greater than 480 °F using the Water Chemistry Control Program. This line item cites Note 35, which states: "Component/material/environment is not addressed in the corresponding NUREG-1801 Chapter, but the component/material/environment is addressed in another NUREG-1801 Chapter." This line Item references AMR line item 3.1.1-36, which provides the following discussion:

> Crack initiation growth due to SCC and flaw growth are identified as aging effects requiring management for the reactor vessel nozzle safe ends, CRD housing, and RCS components. Aging management programs credited for managing these effects are the Water Chemistry Control Program and ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.

The note implies that ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program should have also been applied to LRA Table 3.3.2-2. In RAI 3.3-7, dated March 31, 2005, the staff requested the applicant to explain this discrepancy or make a commitment to review the line Item in LRA Table 3.3.2-2 to include the Inservice Inspection Program. This was identified as open item (OI) 3.3-7.

In its response to OI 3.3-7, by letter dated April 29, 2005, the applicant addressed the staff's concern. Subsequently, by letter dated June 10, 2005, the applicant committed to use the One-Time Inspection Program in conjunction with the Water Chemistry Control Program to manage IGA/IGSCC aging mechanisms. The staff found the applicant's response to RAI 3.3-7 and the addition of the One-Time Inspection Program is an acceptable approach to manage the aging effects. The staff's concern is resolved and, therefore, OI 3.3-7 is closed.

The staff reviewed the applicant's Water Chemistry Control Program and its evaluation is documented in SER Section 3.0.3.2.20. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that cracking due to IGA/IGSCC for component types in the component cooling water system is effectively managed using the Water Chemistry Control Program. Therefore, the staff found that management of cracking due to IGA/IGSCC in the component cooling water system using these programs is acceptable.

3.3.2.3.4 Spent Fuel Cooling System - Aging Management Evaluation - Table 3.3.2-3

The staff reviewed LRA Table 3.3.2-3, as modified by letter dated April 29, 2005, which summarizes the results of AMR evaluations for the spent fuel cooling system component groups.

The spent fuel cooling system experiences loss of material of carbon low-alloy steel, stainless steel, and CASS for the following component types:

- CS components
- fasteners and bolting
- flow elements
- heat exchangers
- filters and strainers
- instrument valve assemblies
- piping and fittings
- pump casings
- valve bodies
- tanks

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- treated water - borated (T<140 °F)(internal)
- raw water (internal)
- indoor - no air conditioning (external)

The staff evaluation with respect to component environments listed as "not applicable" and loss of preload for closure bolting are discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the spent fuel cooling system loss of material aging effects by using the Boric Acid Corrosion Program, Bolting Integrity Program, One-Time Inspection Program, Water Chemistry Control Program, Systems Monitoring Program, and Open-Cycle

Cooling (Service) Water System Surveillance Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.6, 3.0.3.2.4, 3.0.3.2.13, 3.0.3.2.20, 3.0.3.3.2, and 3.0.3.2.14, respectively.

On the basis of its review, the staff found the aging effects of the above spent fuel cooling system component types are consistent with industry experience for these combinations of materials and environments. The staff found that the applicant identified the appropriate aging effects for the material and environment associated with the above components in the spent fuel cooling system.

The applicant proposed to manage loss of heat transfer due to fouling of stainless steel material for component type of heat exchanger exposed to raw water environment using Open-Cycle Cooling (Service) Water System Surveillance Program. The applicant stated that One-Time Inspection Program and Water Chemistry Control Program are used for components exposed to an environment of treated borated water with temperature less than 140 °F.

The staff reviewed the applicant's Open-Cycle Cooling (Service) Water System Surveillance Program, One-Time Inspection Program, and Water Chemistry Control Program and its evaluation of these programs is documented in SER Sections 3.0.3.2.14, 3.0.3.2.13, and 3.0.3.2.20, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of heat transfer due to fouling for component types in the spent fuel cooling system are effectively managed using Open-Cycle Cooling (Service) Water System Surveillance Program, One-Time Inspection Program, and Water Chemistry Control Program. Therefore, the staff found that management of loss of heat transfer due to fouling in the spent fuel cooling system using these programs is acceptable.

3.3.2.3.5 Waste Disposal System - Aging Management Evaluation - Table 3.3.2-4

The staff reviewed LRA Table 3.3.2-4, as modified by letter dated April 29, 2005, which summarizes the results of AMR evaluations for the waste disposal system component groups.

The waste disposal system experiences loss of material of carbon and low-alloy steel, stainless steel, copper alloy (Zn>15%), copper alloy (Zn<15%), cast iron, and CASS for the following component types:

- CS components
- fasteners and bolting
- flow indicators
- heat exchangers
- drain trap
- compressor casing
- filters and strainers
- instrumentation
- level gauges
- piping and fittings
- radiation monitors
- restricting orifices
- sight glass
- tanks
- valve bodies

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- treated water - other (internal)
- treated water - borated (T<140 °F)(internal)
- air and gas - wetted (T<140 °F)(internal)
- raw water drainage (internal)
- indoor - no air conditioning (external)

The staff evaluation with respect to component environments listed as "not applicable" and loss of preload for closure bolting are discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the waste disposal system aging effects by using the Boric Acid Corrosion Program, Bolting Integrity Program, One-Time Inspection Program, Water Chemistry Control Program, Systems Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, and Closed-Cycle Cooling Water System Surveillance Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.6, 3.0.3.2.4, 3.0.3.2.13, 3.0.3.2.20, 3.0.3.3.2, 3.0.3.3.1, and 3.0.3.2.9, respectively.

On the basis of its review, the staff found the aging effects of the above waste disposal system component types are consistent with industry experience for these combinations of materials and environments. The staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the waste disposal system.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material for component types in the waste disposal system is effectively managed using the Boric Acid Corrosion Program, Bolting Integrity Program, One-Time Inspection Program, Water Chemistry Control Program, Systems Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, and Closed-Cycle Cooling Water System Surveillance Program. Therefore, the staff found that management of loss of materials in the waste disposal system using these programs is acceptable.

3.3.2.3.6 Service Water System - 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 service water system component groups.

The service water system experiences loss of material of carbon and low-alloy steel, stainless steel, cast iron, copper alloy (Zn<15%), CASS, and copper alloy (Zn>15%) for the following component types:

- CS components
- expansion joints
- filters and strainers
- fasteners and bolting
- flow elements
- flow indicators
- heat exchangers
- heaters and coolers
- hose reel
- restricting orifices
- sight glass
- radiation monitor
- instrument valve assemblies
- piping and fittings

- pump casings
- thermowells
- valve bodies

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- raw water (velocity)(internal)
- raw water - submerged (external)
- raw water (internal)
- raw water - stagnant (internal)
- indoor - wetted (external)
- buried (external)
- containment (external)
- indoor - no air conditioning (external)

The staff evaluation with respect to component environments listed as "not applicable" and loss of preload for closure bolting are discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the service water system loss of material aging effect by using the Boric Acid Corrosion Program, Fire Protection Program, Buried Services Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, Systems Monitoring Program, Bolting Integrity Program, and Open-Cycle Cooling (Service) Water System Surveillance Program. The staff's evaluations of these programs are documented in Sections 3.0.3.2.6, 3.0.3.2.10, 3.0.3.2.7, 3.0.3.3.1, 3.0.3.3.2, 3.0.3.2.4, and 3.0.3.2.14, respectively.

During the audit, the staff noted that the applicant used Note B for loss of material of copper alloy (Zn<15%) and copper alloy (Zn>15%) for the valve bodies line item. Note B indicates that the component, material, environment, aging effect, and program are consistent with NUREG-1801 with minor exceptions. However, the GALL Report reference does not include copper alloys. The applicant was asked to provide clarification. The applicant stated that although NUREG-1801 Volume 2, reference VII.C1.2-a cited materials that include bronze and aluminum bronze, it does not specifically cite copper alloy. The applicant stated that Note F, which indicates material not in NUREG-1801 for this component, should be used. In its letter, dated July 12, 2004, the applicant stated that it will change the note from B to F,5 in the 2005 LRA update. On this basis, the staff found this change acceptable.

During the audit, the staff noted that the applicant lists numerous line items that define components in an indoor with no air conditioning or external containment environment, and credited the Open-Cycle Cooling (Service) Water System Surveillance Program, for managing the loss of material aging effect. The Open-Cycle Cooling (Service) Water System Surveillance Program description indicates the program is intended to manage loss of material on the internal surfaces of these components. The applicant was requested to explain how the Open-Cycle Cooling (Service) Water System Surveillance Program manages the loss of material of external surfaces of carbon steel thermowells in these external environments.

By letter, dated July 12, 2004, the applicant stated that for external surfaces the Systems Monitoring Program provides for visual inspections and monitoring of external surfaces of piping, tanks, and other components and equipment, for leakage and evidence of material degradation. These inspections and monitoring are able to identify the aging effect of concern (loss of material) on external surfaces, prior to a loss of intended function of these components.

Furthermore, the applicant stated that the Open-Cycle Cooling (Service) Water System Surveillance Program and the Fire Protection Program both provide for wall thickness assessments (looking for this loss of material) to be performed. These wall thickness assessments are typically performed from the outside of the components and, therefore, are able to detect any external surface degradation. For that reason, these two programs augment the Systems Monitoring Program for managing loss of material on the external surfaces of components within the service water system and the fire protection system.

Therefore, the Systems Monitoring Program, augmented in selected cases by the Open-Cycle Cooling (Service) Water System Surveillance Program, or the Fire Protection Program, provides adequate assurance that loss of material on the external surfaces of components will be managed for the period of extended operation. The staff found this acceptable because the implementation of these programs is expected to ensure management of aging effects on external surfaces on these components.

During the audit, the staff also noted that GALL AMP XI.M33, "Selective Leaching of Materials," indicates the susceptibility of cast iron to the aging effect of selective leaching when exposed to a raw water environment. The Open-Cycle Cooling (Service) Water System Surveillance Program is credited with managing the loss of material, but selective leaching is not defined as an aging effect of cast iron pump casing or valve bodies in a submerged raw water environment. The applicant was requested to clarify why this aging effect is not identified for this material, environment, and aging management program combination. The applicant stated that selective leaching was identified as a potential aging effect. The Open-Cycle Cooling (Service) Water System Surveillance Program will be revised to credit the One-Time Inspection Program to identify selective leaching for these components. In its letter dated October 15, 2004, the applicant committed to include, under the One-Time Inspection Program, visual inspections and hardness measurements to identify selective leaching of susceptible components.

On the basis of its review of the applicant's programs, and plant-specific and industry operating experience, the staff found that loss of material for component types in the service water system are effectively managed using the Boric Acid Corrosion Program, Fire Protection Program, Buried Services Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, Systems Monitoring Program, Bolting Integrity Program, and Open-Cycle Cooling (Service) Water System Surveillance Program. Therefore, the staff found that management of loss of materials in the service water system using these programs is acceptable.

The applicant proposed to manage loss of heat transfer due to fouling of copper alloy (Zn<15%) for component type of heater/coolers exposed to indoor - wetted (external) and raw water (velocity) environments using the Open-Cycle Cooling (Service) Water System Surveillance Program and Periodic Surveillance and Preventive Maintenance Program.

The staff reviewed the applicant's Open-Cycle Cooling (Service) Water System Surveillance Program and Periodic Surveillance and Preventive Maintenance Program and its evaluations are documented in SER Sections 3.0.3.2.14 and 3.0.3.3.1, respectively. On the basis of its review of the applicant's programs, and plant-specific and industry operating experience, the staff found that loss of heat transfer due to fouling for component types in the service water system is effectively managed using the Open-Cycle Cooling (Service) Water System Surveillance Program and Periodic Surveillance and Preventive Maintenance Program.

Therefore, the staff found that management of loss of heat transfer due to fouling in the service water system using these programs is acceptable.

In LRA Table 3.3.2-5 the applicant stated that change in material properties is identified by the GALL Report as a potential aging effect for neoprene expansion joints pressure boundaries exposed to indoor with no air conditioning environment. The applicant's evaluation of plant locations with neoprene expansion joint pressure boundaries demonstrated that these neoprene components operate at temperatures less than the 95 °F threshold above which a change in material properties could occur. Therefore, the applicant concluded that no aging effects are expected and no aging management programs are required.

The staff agreed with the applicant that operating conditions experienced by these neoprene expansion joint pressure boundaries are not expected to exceed 95 °F. In addition, the staff agreed that 95 °F is an appropriate threshold for a maximum operating temperature at which no material property changes will occur to neoprene seals.

Based on the operating temperature and threshold limit the staff agreed that the neoprene expansion joint pressure boundaries are not expected to experience material property changes and, therefore, do not require an AMP.

3.3.2.3.7 Fire Protection System - 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 fire protection system component groups.

The fire protection system experiences loss of material of carbon and low-alloy steel, cast iron, copper alloy (Zn<15%), copper alloy (Zn>15%), stainless steel and CASS for the following component types:

- accumulators
- cylinders
- compressor casing
- CS components
- fasteners and bolting
- filters and strainers
- fire hydrant
- flame arrestors
- heat exchangers
- hose reel
- RCP oil collection
- spray nozzles
- sprinkler heads
- instrument valve assemblies
- piping and fittings
- pump casings
- tanks
- valve bodies

For those components requiring staff review, the environments are listed below:

- air and gas - wetted (T<140 °F)(internal)
- borated water leaks (external)
- oil and fuel oil - pooling (internal)
- oil and fuel oil (internal)
- treated water - other (stagnant) (internal)
- buried (external)

- raw water (stagnant)(internal)
- outdoor (external)
- containment (external)
- indoor - no air conditioning (external)

The staff evaluation with respect to component environments listed as "not applicable," heat exchanger inspection frequency for the aging effect of loss of heat transfer due to fouling and aging effects for neoprene expansion joints are discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the fire protection system loss of material aging effects by using the Fire Protection Program, Boric Acid Corrosion Program, Bolting Integrity Program, One-Time Inspection Program, Buried Services Monitoring Program, Fuel Oil Chemistry Control Program and Systems Monitoring Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.10, 3.0.3.2.6, 3.0.3.2.4, 3.0.3.2.13, 3.0.3.2.7, 3.0.3.2.12, and 3.0.3.3.2, respectively.

The staff's review of LRA Table 3.3.2-6 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.

RAI 3.3.2.1.6-1. LRA Table 3.3.2-6 refers to Notes J and 5 which describe the AMPs for certain fire protection component types as listed in the table. In RAI 3.3.2.1.6-1, dated September 10, 2004, the staff requested the applicant to provide justification for the conclusion specified in Note 5 that "the aging management program(s) referenced are appropriate for the aging effects identified and provides assurance that the aging effects are effectively managed through the period of extended operation."

In its response, dated October 8, 2004, the applicant stated that Note J was used whenever a line item could not be matched to any corresponding NUREG-1801, Generic Aging Lessons Learned Report line item. Note 5 simply indicates that, in the applicant's judgment, the program identified would adequately manage the referenced aging effect through the period of extended operation. The justification that the individual identified programs are capable of adequately managing the aging effect is contained in the applicable program descriptions found in LRA Appendix B.

The staff found the applicant's response to RAI 3.3.2.1.6-1 unacceptable. The applicant's response indicates, based on its judgment, that because the AMP for fire protection system components corresponds to Note 5 in LRA Table 3.3.2-6 it is capable of adequately managing the aging effect. The staff concluded that the applicant should address the applicable program for fire protection system components that corresponds to Notes J and 5 in LRA Table 3.3.2-6 to adequately manage the aging effect.

During a meeting, on February 15, 2005, the staff indicated and the applicant agreed that this response required further clarification. The staff indicated that it is unclear where in the LRA the AMPs of certain fire protection components are evaluated. The applicant explained that LRA Section B2.1.10 identified the appropriate AMP to manage loss of material to the fire protection system components exposed to the environment.

In its response to RAI B2.1.7-1, a clarification letter, dated March 15, 2005, the applicant provided new commitments regarding the fire protection system's piping inspection and the

Buried Services Monitoring Program. The applicant stated that a susceptible location in the fire protection system (*i.e.*, uncoated/unwrapped piping) will be scheduled to be inspected once prior to the period of extended operation and at least every 10 years during the period of extended operation. Based upon findings from these fire protection systems inspections, additional inspection locations could include coated and/or uncoated buried piping in the fire protection system, service water system, and fuel oil system. The staff believes that the applicant's response to RAI B2.1.7-1 addressed the concern described in RAI 3.3.2.1.6-1. Furthermore, the Region III staff found, as documented in its inspection report dated May 2, 2005, that the Buried Services Monitoring Program will provide reasonable assurance that the aging effects will be managed so that the buried service water, fuel oil, and fire protection system components will continue to perform their intended function consistent with the CLB during the period of extended operation.

In addition, the staff reviewed LRA Section B2.1.10 and found that the AMP is consistent with GALL Chapter XI.M26, "Fire Protection," Chapter XI.M27 "Fire Water System," with certain enhancements and exceptions. The enhancements include revision to various existing implementing documents to add specific inspections, monitoring and trending requirements, and/or frequency adjustment based on operating experience. Additionally, the applicant committed to create new implementing documents for inspections of selected components and portions of fire suppression piping. The staff considered these types of enhancements as administrative, and not requiring staff review.

The staff reviewed the exceptions and its justifications associated with GALL Chapter XI.M26, Chapter XI.M27, and ISG-04 to evaluate whether the AMPs remain adequate to manage the aging effects for the fire protection system components. The staff noted that ISG-04 did not affect fire protection AMP elements and the applicant conservatively applied the exceptions to its Fire Protection Program.

Based on its review and the above discussion, the staff found the applicant's AMP for fire protection with certain enhancements and exceptions with GALL Chapter XI.M26, Chapter XI.M27, and ISG-04 is adequate to manage the aging effects for the period of extended operation as required by 10 CFR 54.21(a)(3). Therefore, the staff's concern described in RAI 3.3.2.1.6-1 is resolved.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material for component types in the fire protection system are effectively managed using the Fire Protection Program, Boric Acid Corrosion Program, Bolting Integrity Program, One-Time Inspection Program, Buried Services Monitoring Program, Fuel Oil Chemistry Control Program and Systems Monitoring Program. Therefore, the staff found that management of loss of materials in the fire protection system using these programs is acceptable.

In LRA Table 3.3.2-6, the applicant stated that change in material properties is identified by the GALL Report as a potential aging effect to neoprene expansion joint pressure boundaries exposed to an indoor with no air conditioning environment. The applicant stated that it has performed a plant temperature survey and demonstrated that the areas where these neoprene seals exist do not reach temperatures above the 95 °F threshold at which neoprene could exhibit aging effects. Therefore, the applicant concluded in its LRA that no aging effects are expected and that no aging management programs are required.

The staff agreed with the applicant that operating conditions experienced by these neoprene expansion joint pressure boundaries do not exceed 95 °F. In addition, the staff agreed that 95 °F, according to industry practice, is an appropriate threshold for a maximum operating temperature at which no material property changes will occur to neoprene seals.

Based on the operating temperature and threshold limit, the staff agreed that the neoprene expansion joint pressure boundaries are not expected to experience material property changes and, therefore, do not require an aging management program. Additional discussion regarding the aging effects of neoprene expansion joints is documented under general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage loss of heat transfer due to fouling of copper alloy (Zn<15%) material for component type the heater exchangers exposed to treated water - other (stagnant) and raw water (stagnant) environment using the Fire Protection Program.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.10. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of heat transfer due to fouling for component types in the fire protection system is effectively managed using the Fire Protection Program. On this basis, the staff found that management of loss of heat transfer due to fouling in the fire protection system is acceptable.

In LRA Table 3.3.2-6, the applicant stated that cracking due to SCC is identified by the GALL Report as a potential aging effect of CASS material for the component type valve bodies pressure boundaries exposed to oil and fuel oil - pooling environment. The applicant stated that its operating experience has shown no aging effects are expected and no management programs are required. The plant-specific note associated with this AMR line item stated that SCC is not a concern for this material/environment group, due to temperatures being less than 140 °F. This is the threshold for SCC that the staff uses in the GALL Report for CASS.

The staff reviewed the information provided in the LRA, assessed the plant operating experience, and reviewed the 140 °F threshold suggested by the applicant. The staff agreed that the threshold limit of 140 °F is an acceptable threshold below which SCC in CASS will not occur. Furthermore, the PBNP operating experience supports that SCC is not occurring in these CASS components. On these bases, the staff found the applicant's conclusion acceptable.

During the audit, the staff noted that the LRA identified cast iron components in the fire protection system as being monitored by the Fire Protection Program and Systems Monitoring Program. Neither of these programs monitors for selective leaching of cast iron.

The applicant stated under the One-Time Inspection Program that another metal that is susceptible to selective leaching is gray cast iron, which can display this type of aging mechanism even in relatively mild environments. Therefore, this program includes a one-time visual inspection of selected components that may be susceptible to selective leaching. The inspection may include hardness measurements. The one-time inspections will determine whether loss of material due to selective leaching is occurring, and whether the process will affect the ability of the components to perform their intended function(s) for the period of extended operation. A sample of the components (such as piping, valve bodies and bonnets, pump casings, and heat exchanger components), whose materials of construction may include cast iron, brass, bronze, or aluminum bronze, that are exposed to raw water, treated water, or groundwater environment that may lead to selective leaching will be selected for inspection.

RAI B2.1.13-1. In RAI B2.1.13-1, dated September 16, 2004, the staff requested the applicant to provide justification of why a hardness test one-time inspection for selective cast iron components in the fire protection system should not be performed. In its response, dated October 15, 2004, the applicant committed as follows:

> As part of LRA Section B2.1.13, One-Time Inspection Program, a one-time visual inspection and hardness measurement will be performed on accessible locations of a set of components of each material type (*i.e.*, cast iron and brass) to determine whether selective leaching has occurred and whether the resulting loss of strength and/or material will affect the intended functions of these components during the period of extended operation.

The Fire Protection Program and the Systems Monitoring Program will be revised to credit the One-Time Inspection Program to identify selective leaching for these components. The One-Time Inspection Program includes a visual inspection and hardness measurement to identify selective leaching of susceptible components. On the basis of its review and the above discussion, the staff found that the aging management of the fire protection system using these programs is acceptable. The staff concern described in RAI B2.1.13-1 is resolved.

During the audit, the staff noted that the LRA Table 3.3.2-6 stated that, for fire system heat exchangers, the heat transfer function for copper alloy has no external environment or aging effect. Typically there is a raw water environment (service water) or treated water environment (CCW) coolant medium on the shell side of the heat exchanger, which promotes scaling. Significant scaling would prevent the heat transfer function. The heat transfer function is used to monitor the aging effect of scaling. The applicant was requested to identify the environment for the external portion of the heat exchanger tubes. The applicant stated that this, as well as several other similar items in the LRA, is an anomaly associated with how the LRA database identifies environments. Because the "external" environment of the heat exchanger tubes is also the "internal" environment of the heat exchanger, the applicant chose to identify the environment only once (*e.g.*, internal environment of the heat exchanger).

On the basis of its review, the staff found this approach acceptable because the applicant had appropriately identified the environment. Additional discussion regarding the aging effects of loss of heat transfer due to fouling is documented under general RAIs in SER Section 3.3.2.3.

3.3.2.3.8 Emergency Power System - 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 emergency power system component groups.

The emergency power system experiences loss of material of carbon and low-alloy steel, stainless steel, aluminum, cast iron, copper alloy (Zn<15%), CASS, and copper alloy (Zn>15%) for the following component types:

- air motor
- drain trap
- fan and blower housing
- flame arrestors
- instrumentation
- silencer
- tanks
- turbine casing
- turbo-charger
- expansion joints
- filters and strainers
- fasteners and bolting
- flow elements
- flow indicators
- heat exchangers
- heaters
- coolers
- restricting orifices
- sight glass
- instrument valve assemblies
- piping and fittings
- pump casings
- valve bodies

For those components requiring staff review, the environments are listed below:

- air and gas - wetted (T<140 °F)(internal)
- oil and fuel oil - pooling (internal)
- treated water - other (stagnant) (internal)
- outdoor (external)
- oil and fuel oil (internal)
- raw water (internal)
- buried (external)
- indoor - no air conditioning (external)

The staff evaluation with respect to component environments listed as "not applicable," loss of preload for closure bolting, aging effects for neoprene expansion joints, and heat exchanger inspection frequency for the aging effect loss of heat transfer due to fouling, are discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the emergency power system loss of material aging effects by using the Buried Services Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, Systems Monitoring Program, One-Time Inspection Program, Fuel Oil Chemistry Control Program, Bolting Integrity Program, Open-Cycle Cooling (Service) Water System Surveillance Program, Tank Internal Inspection Program, and Closed-Cycle Cooling Water System Surveillance Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.7, 3.0.3.3.1, 3.0.3.3.2, 3.0.3.2.13, 3.0.3.2.12, 3.0.3.2.4, 3.0.3.2.14, 3.0.3.3.3, and 3.0.3.2.9, respectively.

The staff's review of LRA Table 3.3.2-6 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.

RAI 3.3-4. LRA Table 3.3.2-7 identifies no aging effects for carbon/low-alloy steel tanks in a concrete external environment. The staff noted that concrete has a high pH, which is a natural inhibitor for steel; however, concrete contaminated with chlorides or concrete in contact with acidic water will be subject to loss of material due to general, pitting, and crevice corrosion. In RAI 3.3-4, dated November 18, 2004, the staff requested the applicant to state the specific tanks, location and external environment. The staff also requested the applicant to describe how the concrete interfaces with the tanks and to discuss if chlorides or acidic water can be present in this environment.

In its response, dated January 7, 2005, the applicant stated:

> The tanks referenced in Table 3.3.2-7 are fuel oil storage tanks, T-175A & B, reference drawings LR-M-219 Sheet 2 and Sheet 3. These tanks were installed via a modification to add two additional diesel generators in 1995. The 35,000 gallon carbon steel tanks were installed in a below-grade vault that was backfilled with concrete and are part of the diesel building structure. The concrete filled vault is not expected to see any ground water infiltration. The ground and lake water has been analyzed for pH, chlorides, and sulfates and has been determined to be non-aggressive. The tanks are provided with a secondary containment, leak detection system. The tanks were covered with a high density polyethylene (HDPE) membrane system (40 mil thickness) manufactured by Gundle Lining Systems Inc., Houston, Texas. The membrane was applied to the tank before the tank was set in place and the placement of the concrete fill. Because of the membrane/liner the concrete is not in direct contact with the steel and therefore, chloride contamination is not possible. Associated with the membrane/liner is a collection box and piping routed to the building's collection/leakage detection system as shown on drawing LR-M-219, Sheet 2. The tank membrane/liner is monitored weekly for oil and/or water effluent to the building sump. The carbon steel tanks are not subject to chlorides or acidic water and therefore, have no aging effects requiring aging management.

The staff found the applicant's response acceptable because the applicant provided satisfactory explanation of why the carbon steel tanks would not be subject to chlorides or acidic water and would not require aging management. The staff's concern described in RAI 3.3-4 is resolved.

On the basis of its review and RAI response, the staff found the aging effects of the above emergency power system component types are consistent with industry experience for these combinations of materials and environments. The applicant provided a satisfactory explanation of why the carbon steel tanks would not be subject to chlorides or acidic water and would not require aging management. The staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the emergency power system.

The applicant proposed to manage loss of heat transfer due to fouling for copper alloy (Zn<15%), stainless steel, and copper alloy (Zn>15%) materials for component type of heat exchangers and heater/coolers exposed to indoor with no air conditioning, raw water, wetted air and gas with temperature less than 140 °F, oil and fuel, outdoor, and stagnant treated water environment using the One-Time inspection Program, Closed-Cycle Cooling Water System Surveillance Program, Open-Cycle Cooling (Service) Water System Surveillance Program, and Periodic Surveillance and Preventive Maintenance Program.

During the audit, the staff noted that LRA Table 3.3.2-7 identified heat exchangers in the emergency power system that experience the aging effect of loss of heat transfer due to fouling when exposed to an internal environment of wetted air and gas with temperatures less than 140 °F. The applicant credited the Periodic Surveillance and Preventive Maintenance Program for managing the identified aging effects.

The staff also noted that the applicant's Periodic Surveillance and Preventive Maintenance Program stated that "the condition of selected structures and components is monitored through inspection, examination, or testing for evidence of age-related degradation on a specified frequency based on operating experience or other requirements (*e.g.*, Technical Specification or ASME Code requirements). Certain components are also replaced on a given frequency based on operating experience."

As documented in the audit and review report, the applicant was requested to provide the technical basis for crediting the Periodic Surveillance and Preventive Maintenance Program for maintaining the heat transfer function. The applicant stated that a functional test of the heat exchanger to confirm proper heat transfer is not practical. The Periodic Surveillance and Preventive Maintenance Program performs visual inspections of the heat exchanger to ensure surfaces are clean of scaling on other deposits that would negatively impact the heat transfer function. Other components (*e.g.*, diesel generators managed by the Closed-Cycle Cooling Water Surveillance Program) rely on functional tests of the component systems to ensure adequate heat transfer. The applicant also stated that its operating experience also supports this evaluation. On the basis of its review, the staff found this approach acceptable because visual inspections and functional tests are expected to ensure to ensure proper aging management of the heat transfer function of these components.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of heat transfer due to fouling for component types in the emergency power system is effectively managed using the Closed-Cycle Cooling Water System Surveillance Program, Open-Cycle Cooling (Service) Water System Surveillance Program, One-Time Inspection Program, and Periodic Surveillance and Preventive Maintenance Program. Therefore, the staff found that management of loss of heat transfer due to fouling in the emergency power system using these programs is acceptable.

In LRA Table 3.3.2-7, the applicant stated that change in material properties due to elevated temperatures, cracking due to ultraviolet radiation, and ozone are identified by the GALL Report as potential aging effects to neoprene and elastomer expansion joint pressure boundaries exposed to indoor with no air conditioning and air and gas with wetted with temperature less than 140 °F environments. As stated in LRA Note 16, the applicant verified through specific studies of plant locations that the PBNP components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. The plant-specific studies also verified that the locations identified in the AMR line items are also not subject to temperatures where change in material properties or cracking could occur (greater than 95 °F).

The staff reviewed the plant-specific operating history and plant-specific studies conducted by the applicant. On the basis of its review and the above discussion, the staff concluded that no aging effects are expected and no management programs are required. Additional discussion regarding aging effects of neoprene expansion joints is documented under general RAIs in SER Section 3.3.2.3.

In LRA Table 3.3.2-7, the applicant stated that cracking due to SCC is identified by the GALL Report as a potential aging effect of stainless steel material for component type of flow element pressure boundaries exposed to oil and fuel oil in a pooling environment. The applicant stated that its operating experience has shown no aging effects are expected and no management programs are required.

As documented in the audit and review report, the applicant stated that it verified that the *operating temperature's conditions for the locations identified by the AMR line items are less* then 140 °F; therefore, SCC is not an aging concern for the emergency power system.

The staff reviewed the plant-specific operating history and studies conducted by the applicant. On the basis of its review and the above discussion, the staff concluded that no aging effects are expected and no management programs are required.

3.3.2.3.9 *Containment Ventilation System - 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 containment ventilation system component groups.

The containment ventilation system experiences loss of material of carbon and low-alloy steel and copper alloy (Zn<15%) for the following component types:

- accumulators and cylinders
- CS components
- damper housing
- ductwork
- fan and blower housing
- fastener and bolting
- heat exchangers
- heaters and coolers
- piping and fittings
- thermowells
- valve bodies
- filters and strainers

For those components requiring staff review, the environments are listed below:

- containment (external)
- borated water leaks (external)
- indoor - wetted (external)
- raw water (internal)
- *indoor - no air conditioning (external)*

The staff evaluation with respect to loss of preload for closure bolting is discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the containment ventilation loss of material aging effects by using the Boric Acid Corrosion Program, Systems Monitoring Program, Bolting Integrity Program, and Open-Cycle Cooling (Service) Water System Surveillance Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.6, 3.0.3.3.2, 3.0.3.2.4, and 3.0.3.2.14, respectively.

The staff found that the applicant identified the appropriate AMPs for the materials and environments associated with the above components in the containment ventilation system.

The applicant proposed to manage loss of heat transfer due to fouling on HX copper alloy (Zn<15%) materials for component types of heat exchangers, heaters and coolers exposed to containment and raw water environment using Open-Cycle Cooling (Service) Water System Surveillance Program, and Periodic Surveillance and Preventive Maintenance Program.
In LRA Table 3.3.2-8, the applicant identified that heaters/coolers in the containment ventilation system experience the aging effect of loss of heat transfer due to fouling when exposed to an

internal environment of raw water and an external environment of containment. The applicant, in the LRA, credited the Periodic Surveillance and Preventive Maintenance Program for managing the identified aging effects.

During the review, the staff noted that the applicant's Periodic Surveillance and Preventive Maintenance Program states that "the condition of selected structures and components is monitored through inspection, examination, or testing for evidence of age-related degradation on a specified frequency based on operating experience or other requirements (*e.g.*, Technical Specification or ASME Code requirements). Certain components are also replaced on a given frequency based on operating experience." The applicant was asked to provide the technical basis for crediting this program for maintaining the heat transfer function. The applicant stated that a functional test of the coolers/heat exchangers/heaters to confirm proper heat transfer is not practical. The Periodic Surveillance and Preventive Maintenance Program performs visual inspections of the heat exchangers to ensure surfaces are clean of scaling or other deposits that would negatively impact the heat transfer function. In addition, the applicant stated that its operating experience also supports this evaluation. The staff found this approach and the use of this program as a means of detecting aging effects is acceptable to ensure the proper aging management of the heat transfer function of these components.

In LRA Table 3.3.2-8, the applicant stated that change in material properties due to elevated temperatures, cracking due to elevated temperatures, cracking due to ultraviolet radiation, and ozone are identified by the GALL Report as potential aging effects to elastomer material of component type valve body exposed to indoor - no air conditioning, air and gas, and containment environment. As stated in LRA Note 16, the applicant verified through specific studies of plant locations that the components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. The plant-specific studies identified that the locations in the AMR line items are not subject to temperatures where change in material properties or cracking could occur (greater than 95 °F).

The staff reviewed the plant-specific operating history and plant-specific studies conducted by the applicant. On the basis of its review, the staff concluded that no aging effects are expected and no management programs are required.

3.3.2.3.10 Essential Ventilation System - 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 essential ventilation system component groups.

The essential ventilation system experiences loss of material of carbon and low-alloy steel, stainless steel, cast iron, and copper alloy (Zn<15 %) for the following component types:

- damper housing
- ductwork
- fan and blower housing
- fasteners and bolting
- filters and strainers
- flow element
- humidifiers
- instrument valve assemblies
- heat exchangers
- heater and coolers
- piping and fittings
- thermowells
- pump casing
- tanks
- valve bodies

For those components requiring staff review, the environments are listed below:

- air and gas - wetted (T<140 °F)(internal)
- treated water - other (internal)
- raw water (velocity)(internal)
- raw water (internal)
- indoor - no air conditioning (external)

The staff evaluation with respect to component environments listed as "not applicable," loss of preload for closure bolting, and heat exchanger inspection frequency for the aging effect loss of heat transfer due to fouling are discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the essential ventilation loss of material aging effects by using the One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program, Systems Monitoring Program, Bolting Integrity Program, Open-Cycle Cooling (Service) Water System Surveillance Program, and Closed-Cycle Cooling Water System Surveillance Program. The staff's evaluation of these programs are documented in SER Sections 3.0.3.2.13, 3.0.3.3.1, 3.0.3.3.2, 3.0.3.2.4, 3.0.3.2.14, and 3.0.3.2.9, respectively.

On the basis of its review, the staff found the aging effects of the above essential ventilation system component types are consistent with industry experience for these combinations of materials and environments. The staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the essential ventilation system.

In LRA Table 3.3.2-9, the applicant stated that change in material properties due to elevated temperatures, cracking due to elevated temperatures, cracking due to ultraviolet radiation, and ozone are identified by the GALL Report as a potential aging effect of elastomer material for component type ductwork pressure boundaries exposed to indoor with no air conditioning and wetted air and gas, temperature less than 140 °F environments. As stated in LRA Note 16, the applicant verified through specific studies of plant locations that the components are indoors and not subject to UV or ozone, nor are they in locations that are subject to radiation exposure. The plant-specific studies also verified that the locations identified in the AMR line items are also not subject to temperatures where change in material properties or cracking could occur (greater than 95 °F).

The staff reviewed the plant-specific operating history and plant-specific studies conducted by the applicant. On the basis of its review, the staff concluded that no aging effects are expected and no management programs are required.

The applicant proposed to manage loss of heat transfer due to fouling of stainless steel and copper alloy (Zn<15%) materials for component type heat exchangers and heater coolers exposed to treated water - other, wetted air and gas, temperature less than 140 °F, raw water - velocity, and raw water environment using the Closed-Cycle Cooling Water System Surveillance Program, Open-Cycle Cooling (Service) Water System Surveillance Program, and Periodic Surveillance and Preventive Maintenance Program.

The staff reviewed the applicant's Closed-Cycle Cooling Water System Surveillance Program, Open-Cycle Cooling (Service) Water System Surveillance Program, and Periodic Surveillance and Preventive Maintenance Program. The staff evaluations of these programs are documented in SER Sections 3.0.3.2.9, 3.0.3.3.14, and 3.0.3.3.1, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of heat transfer due to fouling for component types in the essential ventilation system are effectively managed using Closed-Cycle Cooling Water System Surveillance Program, Open-Cycle Cooling (Service) Water System Surveillance Program, and Periodic Surveillance and Preventive Maintenance Program. Therefore, the staff found that management of loss of heat transfer due to fouling in the essential ventilation system using these programs is acceptable.

3.3.2.3.11 Plant Sampling System - Aging Management Evaluation - Table 3.3.2-10

The staff reviewed LRA Table 3.3.2-10, as modified by letter dated April 29, 2005, which summarizes the results of AMR evaluations for the plant sampling system component groups.

In the original LRA Table 3.3.2-10, the applicant stated that those few components from the plant sampling system requiring aging management had been addressed under the reactor coolant system, residual heat removal system, chemical volume and control system, and the component cooling water system. The staff's evaluations of these systems are documented in SER Sections 3.1.2.3.1, 3.2.2.3.4, 3.3.2.3.2, and 3.3.2.3.3, respectively.

As a result of the methodology changes, more components within the plant sampling system are now considered within the scope of license renewal. The newly identified components include the tubing runs and valves from containment isolation valves or various sample locations to the primary sample room. The inclusion of these components resulted in the creation of a new LRA Table 3.3.2-10. However, those items originally covered in other interfacing systems were left in those other systems.

The plant sampling system experiences loss of material of stainless steel for the following component types:

- filters and strainers
- level gauges
- piping and fittings
- restricting orifices
- tanks
- valve bodies

For those components requiring staff review, the environments are listed:

- treated water - secondary (T<120 °F)(internal)
- treated water - secondary (T>120 °F)(internal)
- treated water - borated (T<140 °F)(internal)
- treated water - primary (140 °F<T<480 °F)(internal)

The applicant proposed to manage the plant sampling system loss of material aging effects by using the One-Time Inspection Program and Water Chemistry Control Program. The staff's evaluations of these programs are documented in SER Section 3.0.3.2.13 and 3.0.3.2.20, respectively.

On the basis of its review, the staff found the aging effects of the above plant sampling system component types consistent with industry experience for those combinations of materials and environments. The staff found that the applicant had identified the appropriate aging effects for the above materials and environments.

In the revised LRA Table 3.3.2-10, the applicant stated that cracking due to SCC is identified as a potential aging effect for stainless steel material for component types of piping, fittings and valve bodies exposed to primary treated water for temperatures between 140 °F and 480 °F and secondary treated water for temperatures greater than 120 °F. The applicant also stated that the One-Time Inspection Program and the Water Chemistry Control Program are used for managing this aging effect.

The staff reviewed the One-Time Inspection Program and the Water Chemistry Control Program and its evaluations are documented in SER Section 3.0.3.2.13 and 3.0.3.2.20, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that cracking due to SCC for component types in the plant sampling systems is adequately managed by using the One-Time Inspection Program and the Water Chemistry Control Program.

3.3.2.3.12 Plant Air System - 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 plant air system component groups.

The plant air system experiences loss of material of carbon and low-alloy steel, stainless steel, cast iron, copper alloy (Zn>15%), and copper alloy (Zn<15%) for the following component types:

- accumulators and cylinders
- compressor casings
- CS components
- fasteners and bolting
- piping and fittings
- tanks
- valve bodies

For those components requiring staff review, the environments are listed below:

- containment (external)
- borated water leaks (external)
- air and gas - wetted (T<140°F)(internal)
- indoor - no air conditioning (external)

The staff evaluation with respect to loss of preload for closure bolting is discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the plant air system loss of material aging effects by using the Boric Acid Corrosion Program, Periodic Surveillance and Preventive Maintenance Program, Systems Monitoring Program, and Bolting Integrity Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.6, 3.0.3.3.1, 3.0.3.3.2, and 3.0.3.2.4, respectively.

On the basis of its review, the staff found the aging effects of the above plant air system component types are consistent with industry experience for these combinations of materials and environments. The staff found that the applicant had identified the appropriate aging effects for the materials and environments associated with the above components in the plant air system.

During the review, the staff noted that the applicant also stated, in LRA Table 3.3.2-11, that a cast iron compressor exposed to an air/gas internal environment experiences no aging effects and no aging management program is required. The applicant was requested to provide the technical basis for not considering any aging effect or aging management program for this specific material/environment. The applicant stated that the component was the charging pump speed controller backup compressor; and that although its plant-specific operating experience supports no aging effects for this component, the applicant acknowledged that the component is susceptible to general corrosion for cast iron in an air and gas (not dried) environment. The applicant also stated that it will revise the aging management review results to identify the aging effect loss of material (due to general corrosion) and identify Periodic Surveillance and Preventive Maintenance Program as the applicable aging management program. In its letter dated July 12, 2004, the applicant committed to revise the aging management review results for the charging pump speed controller back-up air compressor to include loss of material due to general corrosion that will be managed by the Periodic Surveillance and Preventive Maintenance Program. The staff found this acceptable because with these changes, proposed in its letter, the applicant ensures detection and management of loss of material.

Also, the staff noted that, in LRA Table 3.3.2-11, the applicant stated that copper alloy material for component type valve bodies in an air and gas wetted internal environment experiences loss of material and the Periodic Surveillance and Preventive Maintenance Program monitors this aging effect. The notes for this line item indicated that this is consistent with NUREG-1801 for material, environment, and aging effect, but a different aging management program is credited. The notes also stated that the material is not evaluated in NUREG-1801 for this component. The applicant was requested to provide a justification as to why this is not a contradiction to the term "consistent with NUREG-1801." The applicant stated that the note is incorrect and will be changed to delete Note F, for material not in NUREG-1801 for this component. By letter dated July 12, 2004, the applicant committed to correct the notes in the 2005 annual LRA update. The staff found this acceptable.

3.3.2.3.13 Containment Hydrogen Detectors and Recombiner System - Aging Management Evaluation - Table 3.3.2-12

The staff reviewed LRA Table 3.3.2-12, which summarizes the results of AMR evaluations for the containment hydrogen detector and recombiner system component groups.

The containment hydrogen detectors and recombiner system experiences loss of material of carbon and low-alloy steel for the following component types:

- CS components
- fasteners and bolting

- piping and fittings
- valve bodies

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- indoor - no air conditioning (external)

The staff evaluation with respect to component loss of preload for closure bolting is discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the containment hydrogen detector and recombiner system loss of material aging effects by using the Boric Acid Corrosion Program, Systems Monitoring Program, and Bolting Integrity Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.6, 3.0.3.3.2, and 3.0.3.2.4, respectively.

On the basis of its review, the staff found the aging effects of the above containment hydrogen detector and recombiner system component types are consistent with industry experience for these combinations of materials and environments. The staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the containment hydrogen detector and recombiner system.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material for component types in the containment hydrogen detector and recombiner system is effectively managed using the Boric Acid Corrosion Program, Systems Monitoring Program, and Bolting Integrity Program. Therefore, the staff found that management of loss of material in the containment hydrogen detector and recombiner system using these programs is acceptable.

3.3.2.3.14 Circulating Water System - 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 circulating water component groups.

The circulating water system experiences loss of material of carbon and low-alloy steel and cast iron for the following component types:

- fasteners and bolting
- piping and fittings
- pump casing
- valve bodies

For those components requiring staff review, the environments are listed below:

- indoor - no air conditioning (external)
- raw water (internal)

The staff evaluation with respect to component loss of preload for closure bolting and aging effects for neoprene expansion joints is discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the circulating water system loss of material aging effects by using the Systems Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, and Bolting Integrity Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.3.2, 3.0.3.3.1 and 3.0.3.2.4, respectively.

On the basis of its review, the staff found the aging effects of the above circulating water system component types are consistent with industry experience for these combinations of materials and environments. The staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the circulating water system.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material for component types in the circulating water system are effectively managed using the Systems Monitoring Program, Periodic Surveillance and Preventive Maintenance Program, and Bolting Integrity Program. Therefore, the staff found that management of loss of material in the circulating water system using these programs is acceptable.

3.3.2.3.15 Treated Water System - Aging Management Evaluation - Table 3.3.2-14

The staff reviewed LRA Table 3.3.2-14, as modified by letter dated April 29, 2005, which summarizes the results of AMR evaluations for the treated water system component groups.

The treated water system experiences loss of material of carbon and low-alloy steel, copper alloy (Zn<15%), stainless steel, and CASS for the following component types:

- CS components
- fasteners and bolting
- filters and strainers
- heat exchangers
- piping and fittings
- valve bodies

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- raw water drainage (internal)
- treated water - other (internal)
- indoor - no air conditioning (external)

The staff evaluation with respect to component loss of preload for closure bolting is discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage the treated water system loss of material aging effects by using the Bolting Integrity Program, Boric Acid Corrosion Program, One-Time Inspection Program, and Systems Monitoring Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.4, 3.0.3.2.6, 3.0.3.2.13 and 3.0.3.3.2, respectively.

The staff's review of LRA Table 3.3.2-14 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.

RAI 3.3-3. LRA Table 3.3.2-14 identifies loss of material as an aging effect of carbon steel piping and fittings, and valve bodies in a raw water drainage (internal) environment. The applicant identifies the One-Time Inspection Program, B2.1.13, to manage this aging effect. The GALL Report, XI.M32 recommends one-time inspections where either an aging effect is not expected to occur but there is insufficient data to completely rule it out, or an aging effect is expected to progress very slowly. In cases where an aging effect is likely to occur, the GALL Report recommends periodic inspections. In RAI 3.3-3, dated November 18, 2004, the staff requested the applicant to justify the use of a One-Time Inspection Program to manage the loss of material for carbon steel components in a raw water environment since aging effects are expected to occur in this environment.

In its response, dated January 7, 2005, the applicant stated:

> The components in question are drainage and sump pump discharge piping and valves that are all shown on drawing LR-M-223 Sheet 3, location G-8. The internal environment is referred to as "Raw Water - Drainage," but this will typically consist of ground-water coming from the Facade Sumps. Groundwater at PBNP is a non-aggressive environment (see LRA Table 3.5.0-1, responses to items 12 and 13). As this is a non-aggressive environment, we would expect any aging effects to proceed very slowly. Plant operating experience over 34 years of operation has not identified any leakage from these lines. Based on the non-aggressive environment and our *plant-specific* operating experience, the use of one-time inspections to manage this aging effect was considered acceptable. A one-time inspection will provide ample indication of the condition of these components prior to the period of extended operation. Note that the One-Time Inspection Program provides for the option to change to periodic inspections or provide for repairs based on the results of the condition assessment after the one-time inspection.

The staff found the applicant's response acceptable. The applicant provided a satisfactory justification for the use of a one-time inspection to manage loss of material for carbon steel components in a raw water environment. The staff's concern described in RAI 3.3-3 is resolved.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material for component types in the treated water system are effectively managed using the Bolting Integrity Program, Boric Acid Corrosion Program, One-Time Inspection Program, and Systems Monitoring Program. Therefore, the staff found that management of loss of material in the treated water system using these programs is acceptable.

3.3.2.3.16 Heating Steam System - 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 heating steam system component groups. The heating steam system experiences loss of material of carbon and low-alloy steel, copper alloy (Zn<15%), stainless steel, and cast iron for the following component types:

- CS components
- fasteners and bolting
- filters and strainers
- heaters and coolers
- piping and fittings
- pump casing
- steam traps
- tanks
- valve bodies

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- treated water - secondary (T>120 °F)(internal)
- indoor - no air conditioning (external)

The staff evaluation with respect to component loss of preload for closure bolting is discussed under the general RAIs in SER Section 3.3.2.3.

The applicant proposed to manage cracking due to SSC on stainless steel material on component type of tanks by using the One-Time Inspection Program and Water Chemistry Control Program.

The applicant proposed to manage the heating steam system loss of material aging effects by using the Boric Acid Corrosion Program, Bolting Integrity Program, One-Time Inspection Program, Water Chemistry Control Program, and Systems Monitoring Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.6, 3.0.3.2.4, 3.0.3.2.13, 3.0.3.3.20, and 3.0.3.3.2, respectively.

On the basis of its review of the information provided in the LRA, the staff found the aging effects of the above heating steam system component types are consistent with industry experience for these combinations of materials and environments. The staff found that the applicant identified the appropriate aging effects for the materials and environments associated with the above components in the heating steam system.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material for component types in the heating steam system are effectively managed using the Boric Acid Corrosion Program, Bolting Integrity Program, One-Time Inspection Program, Water Chemistry Control Program, and Systems Monitoring Program. Therefore, the staff found that management of loss of material in the heating steam system using these programs is acceptable.

3.3.2.3.17 Fuel Handling System - 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 fuel handling system component groups.

In LRA Table 3.3.2-16, the applicant stated that aging management of the fuel handling system component groups is addressed under the spent fuel cooling system, Units 1 and 2 containment building structure and the primary auxiliary building structure. The staff's evaluations of these systems are discussed in SER Sections 3.3.2.3.4, 3.5.2.3.2 and 3.5.2.3.7, respectively.

3.3.3 Conclusion

On the basis of its review, the staff concluded that the applicant demonstrated that the aging effects associated with the auxiliary systems components 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 FSAR 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 Systems

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

- main and auxiliary steam system
- feedwater and condensate system
- auxiliary feedwater system

3.4.1 Summary of Technical Information in the Application

In LRA Section 3.4, the applicant provided AMR results for steam and power conversion system components and component groups. In LRA Table 3.4.1, "Summary of Aging Management Evaluations in Chapter VIII of NUREG-1801 for Steam and Power Conversion System," 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 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 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.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine if the applicant 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).

Also, the staff performed an onsite audit 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 determine that the material presented in the LRA was applicable and that the applicant had identified the appropriate GALL AMPs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluations are documented in the staff's PBNP audit and review report and summarized in SER Section 3.4.2.1.

The staff also performed an onsite audit of those AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff verified that the applicant's further evaluations were consistent with the acceptance criteria in NUREG-1800, Section 3.4.2.2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated July 2001. The staff's audit evaluations are documented in the staff's PBNP audit and review report and summarized in SER Section 3.4.2.2.

The staff performed an onsite audit and conducted a technical review of the remaining AMRs that were not consistent with the GALL Report. The audit and technical review included evaluating whether all plausible aging effects had been identified and the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the staff's PBNP audit and review report and summarized in Section SER 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 FSAR 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 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 AFW piping (PWR only) (Item Number 3.4.1-01)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue (See Section 3.4.2.2.1)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Piping and fittings, valve bodies and bonnets, pump casings, tanks, tubes, tubesheets, channel head and shell (except main steam system) (Item Number 3.4.1-02)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Water chemistry and one-time inspection	Water Chemistry Control Program; One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program; Tank Internal Inspection Program	Consistent with GALL, which recommends further evaluation. (See Section 3.4.2.2.2)
AFW piping (Item Number 3.4.1-03)	Loss of material due to general, pitting, and crevice corrosion, MIC, and biofouling	Plant-specific	Not Applicable	Not Applicable (See Section 3.4.2.2.3)
Oil coolers in AFW system (lubricating oil side possibly contaminated with water) (Item Number 3.4.1-04)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion and MIC	Plant-specific	Periodic Surveillance and Preventive Maintenance Program	Consistent with GALL, which recommends further evaluation. (See Section 3.4.2.2.5)
External surface of carbon steel components (Item Number 3.4.1-05)	Loss of material due to general corrosion	Plant-specific	Systems Monitoring Program	Consistent with GALL, which recommends further evaluation. (See Section 3.4.2.2.4)
Carbon steel piping and valve bodies (Item Number 3.4.1-06)	Wall thinning due to flow-accelerated corrosion	Flow-accelerated corrosion	Flow-Accelerated Corrosion Program, Water Chemistry Control Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.4.2.1)
Carbon steel piping and valve bodies in main steam system (Item Number 3.4.1-07)	Loss of material due to pitting and crevice corrosion	Water chemistry	Water Chemistry Control Program; One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.4.2.1)
Closure bolting in high-pressure or high-temperature systems (Item Number 3.4.1-08)	Loss of material due to general corrosion; crack initiation and growth due to cyclic loading and/or SCC	Bolting integrity	Bolting Integrity 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
Heat exchangers and coolers/condensers serviced by OCCW (Item Number 3.4.1-09)	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	Open-Cycle Cooling (Service) Water System Surveillance Program; One-Time Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.4.2.1)
Heat exchangers and coolers/condensers serviced by CCCW (Item Number 3.4.1-10)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Closed-cycle cooling water system	Not Applicable	Not Applicable
External surface of above-ground CST (Item Number 3.4.1-11)	Loss of material due to general (carbon steel only), pitting, and crevice corrosion	Above-ground carbon steel tanks	Not Applicable	Not Applicable
External surface of buried CST and AFW piping (Item Number 3.4.1-12)	Loss of material due to general, pitting, and crevice corrosion and MIC	Buried piping and tanks surveillance or Buried piping and tanks inspection	Not Applicable	Not Applicable (See Section 3.4.2.2.5)
External surface of carbon steel components (Item Number 3.4.1-13)	Loss of material due to boric acid corrosion	Boric acid corrosion	Boric Acid Corrosion Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.4.2.1)

The staff's review of the PBNP steam and power conversion system and associated components 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 system 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 the GALL Report or are 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 aging effects requiring management. The applicant identified the following programs that manage the aging effects related to the main steam, main feedwater, and emergency feedwater system components:

- Bolting Integrity Program;
- Boric Acid Corrosion Program;
- Flow-Accelerated Corrosion Program;
- One-Time Inspection Program;
- Open-Cycle Cooling (Service) Water System Surveillance Program;
- Periodic Surveillance and Preventive Maintenance Program;
- Systems Monitoring Program;
- Tank Internal Inspection Program; and
- Water Chemistry Control Program.

Staff Evaluation. In LRA Tables 3.4.2-1 through 3.4.2-3, the applicant provided a summary of AMRs for the main steam, auxiliary steam, main feedwater, auxiliary feedwater, and condensate 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 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's audit of those AMRs with Notes A through E, 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, although different, is 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, although different, is 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 aging management program 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 PBNP 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 have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the steam and power conversion 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 3.4.1 (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 found 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 found 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).

3.4.2.2 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 provides further evaluation of aging management as recommended by the GALL Report for steam and power conversion system. 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, microbiologically influenced corrosion (MIC), and biofouling;
- general corrosion; and
- loss of material due to general, pitting, and crevice corrosion, and MIC.

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 reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated. In addition, the staff audited the applicant's further evaluations against the criteria in SRP-LR Section 3.4.2.2. Details of the staff's audit review are documented in the staff's audit and review report. The staff's evaluation is discussed below.

3.4.2.2.1 Cumulative Fatigue Damage

In LRA Section 3.4.2.2.1, 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 LRA Section 3.4.2.2.2 against the criteria in SRP-LR 3.4.2.2.2.

SRP-LR Section 3.4.2.2.2 states that management of 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 for loss of material due to pitting and crevice corrosion for stainless steel tanks and heat exchanger/cooler tubes.

The Water Chemistry Control Program relies on monitoring and control of water chemistry based on the guidelines in EPRI guideline TR-102134 for secondary water chemistry to manage the effects of loss of material due to general, pitting, or crevice corrosion. 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 Water Chemistry Control

Program. A one-time inspection of select components and 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 AMPs recommended by the GALL Report for management of this aging effect are GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M32, "One Time Inspection."

In LRA Section 3.4.2.2.2, the applicant stated that the loss of material due to general, pitting and crevice corrosion, for the steam and power conversion components, are managed by the Water Chemistry Control Program and the One-Time Inspection Program. Additionally, aging effects for selected components are managed by the Periodic Surveillance and Preventive Maintenance Program or the Tank Internal Inspection Program.

The applicant stated that for its steam and power conversion components, it credited the Water Chemistry Control Program and the One-Time Inspection Program for managing these aging effects/mechanisms. The applicant stated that in addition to these programs, the Periodic Surveillance and Preventive Maintenance Program and Tank Internal Inspection Program are also credited for managing a few selected components. Also, the applicant's existing Water Chemistry Control Program relies on the guidelines of EPRI TR-102134 for secondary water chemistry to manage the effects of loss of material due to general, pitting, or crevice corrosion.

The staff reviewed the applicant's Water Chemistry Control Program, One-Time Inspection Program, Periodic Surveillance and Preventive Maintenance Program, and Tank Internal Inspection Program. The staff's evaluation is documented in SER Sections 3.0.3.2.20, 3.0.3.2.13, 3.0.3.3.1, and 3.0.3.3.3, respectively. The staff found that the applicant's Water Chemistry Control Program minimizes loss of material by providing a non-aggressive material environment and the Periodic Surveillance and Preventive Maintenance Program supplement water chemistry control for portions of the emergency feedwater system. In addition, the Periodic Surveillance and Preventive Maintenance Program provides for the inspection of systems when they are opened for maintenance, which achieves the same results as the One-Time Inspection Program, which is recommended in the GALL Report.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.4.2.2.2 for further evaluation. For those items that apply to LRA Section 3.4.2.2.2, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained 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

The staff reviewed LRA Section 3.4.2.2.3 against the criteria in SRP-LR 3.4.2.2.3.

SRP-LR Section 3.4.2.2.3 states that loss of material due to general corrosion, pitting and crevice corrosion, MIC, and biofouling could occur in carbon steel piping and fittings for untreated water from the backup water supply in the PWR auxiliary feedwater system. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed. Acceptance criteria are described in Branch Technical Position RLSB-1 (SRP-LR Section A.1).

In LRA Table 3.4.1, Item 3.4.1-03, the applicant stated that this line item is not used. The applicant stated that the components identified in this line item relate to the portion of the auxiliary feedwater piping system that is exposed to the untreated water from the backup water supply. These components are evaluated under the service water system in LRA Section 3.3.2.1.5, which is addressed in NUREG-1801, Chapter VII (Auxiliary Systems), Section C1.

The aging management programs identified by the applicant constitute the equivalent plant-specific aging management program discussed in SRP-LR Section 3.4.2.2.3. As stated by the applicant, these components are not listed in LRA Section 3.4; hence, it is reasonable to not explicitly use the further evaluation criteria discussed in SRP-LR Section 3.4.2.2.3. However, the applicant does manage the aging effect for these components as part of the service water system in LRA Section 3.3. Based on the programs identified and inspections that will be performed, the applicant has met the criteria of SRP-LR Section 3.4.2.2.2 for further evaluation.

The applicant stated that the aging effects of the lines from the service water system to the emergency feedwater system that are exposed to untreated water are managed using the Open-Cycle Cooling (Service) Water Surveillance Program.

The staff reviewed the applicant's Open-Cycle Cooling (Service) Water Surveillance Program and its evaluation is documented in SER Section 3.0.3.3.2.14. The staff found that this program includes scheduled walkdowns and selected high-susceptibility teardown and inspection to detect loss or material degradation. Based on the content of this program, the staff found use of this AMP acceptable.

For those items that apply to LRA Section 3.4.2.2.3, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2.4 General Corrosion

The staff reviewed LRA Section 3.4.2.2.4 against the criteria in SRP-LR 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 boltings, exposed to operating temperature less than 212 °F. The GALL Report recommends further evaluation to ensure that this aging effect is adequately managed.

The applicant stated that it credited the Systems Monitoring Program for managing aging effects for normally accessible, external surfaces of piping, tanks, and other components and equipment within the scope of license renewal. These aging effects are managed through visual inspection and monitoring of external surfaces for leakage and evidence of material degradation.

The staff reviewed the applicant's Systems Monitoring Program and its evaluation is documented in SER Section 3.0.3.3.2. On the basis of its review, the staff found that the Systems Monitoring Program adequately manages the loss of material due to general corrosion for the above components.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.4.2.2.4 for further evaluation. For those items that apply to LRA Section 3.4.2.2.4, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained 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, and Crevice Corrosion, Microbiologically Influenced Corrosion

The staff reviewed LRA Section 3.4.2.2.5 against the criteria in SRP-LR 3.4.2.2.5.

In LRA Section 3.4.2.2.5, the applicant addressed (1) the oil side of bearing oil coolers in the auxiliary feedwater system, and (2) the line item related to buried components in the auxiliary feedwater system.

SRP-LR Section 3.4.2.2.5 addresses loss of material due to general corrosion (carbon steel only), as well as pitting and crevice corrosion and MIC, which could occur in stainless steel and carbon steel shells, tubes, and tubesheets within the bearing oil coolers (for steam turbine pumps) in the auxiliary feedwater system. The GALL Report recommends further evaluation to ensure that these aging effects are adequately managed.

SRP-LR 3.4.2.2.5 also addresses loss of material due to general corrosion, pitting and crevice corrosion, and MIC, which could occur in underground piping and fittings, the emergency condensate storage tank in the auxiliary feedwater system, and the underground condensate storage tank in the condensate system.

The applicant credited its plant-specific Periodic Surveillance and Preventive Maintenance Program for managing the aging effects/mechanisms of part (1) of this line item. In addition, the applicant stated that it does not have buried components in the steam and power conversion systems and, therefore, part (2) of this line item is not applicable.

The staff reviewed the applicant's Periodic Surveillance and Preventive Maintenance Program and its evaluation is documented in SER Section 3.0.3.3.1. On the basis of its review, the staff found that the Periodic Surveillance and Preventive Maintenance Program adequately manages the effects of aging of loss of material for stainless and carbon steel components exposed to lubricating oil (with water contamination). Also, the staff found that there are no buried components in steam and power conversion systems at PBNP, as documented in the staff's audit and review report.

The staff found that, based on the programs identified above, the applicant has met the criteria of SRP-LR Section 3.4.2.2.5 for further evaluation. For those items that apply to LRA Section 3.4.2.2.5, the staff found that the applicant is consistent with the GALL Report and has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained during the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 3.4.2-3, the staff reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not evaluated in the GALL Report or are not addressed in the GALL Report.

As documented under RAI 2.1-1 in SER Section 2.1, by letter dated April 29, 2005, the applicant changed the methodology used to determine the nonsafety-related SCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). As a result of the implementation of the scoping methodology changes, the applicant identified changes to LRA Tables 3.4.2-1 and 3.4.2-2.

In LRA Tables 3.4.2-1 through 3.4.2-3, 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.

3.4.2.3.1 Steam and Power Conversion System Components That Have No Aging Effects - Tables 3.4.2-1 through 3.4.2-3

In LRA Tables 3.4.2-1 through 3.4.2-3, the applicant identified line items where no aging effects were identified as a result of the aging review process. Specifically, the applicant identified that no aging effects occurred when components fabricated from carbon/alloy steel, stainless steel, aluminum, copper alloy, or CASS were exposed to air or to an inert gas (*e.g.*, nitrogen). Neither air nor inert gas is identified in the GALL Report as an environment for these components and materials. No aging effects are considered to be applicable to carbon/alloy steel, stainless steel, aluminum, copper alloys, or CASS components in air (defined as dehumidified atmospheric air, dry/filtered instrument air) or inert gas environments.

On the basis of its review of current industry research and operating experience, the staff found that dry air on metal will not result in aging that will be of concern during the period of extended operation. Stainless steel and nickel-based alloy components in air or an inert gas environment are not susceptible to general corrosion that would affect their intended function. Therefore, the staff concluded that there are no applicable aging effects requiring management for carbon/alloy steel, stainless steel, aluminum, copper alloy, or CASS exposed to air, or to an inert gas environment.

3.4.2.3.2 Main and Auxiliary Steam System - Aging Management Evaluation - Table 3.4.2-1

The staff reviewed LRA Table 3.4.2-1, as modified by letter dated April 29, 2005, which summarizes the results of AMR evaluations for the main and auxiliary steam system component groups.

The main and auxiliary steam system experiences loss of material of copper alloy (Zn<15%) cast iron, carbon and low-alloy steels, and stainless steel for the following component types:

- CS components
- drain trap
- fasteners and bolting
- filters and strainers
- flow elements
- heat exchangers
- instrument valve assemblies
- piping and fittings
- pump casing
- restricting orifices
- steam traps
- tanks
- valve bodies
- level gauges

For those main and auxiliary steam system components requiring staff review, the environments are listed below:

- borated water leaks (external)
- indoor - no air conditioning (external)
- treated water - secondary (T<120 °F)(internal)
- treated water - secondary (T>120 °F)(internal)
- containment (external)
- air and gas - wetted (T<140 °F)(internal)
- outdoor (external)

The applicant proposed to manage the main and auxiliary steam system loss of material aging effects by using the Bolting Integrity Program, Boric Acid Corrosion Program, Periodic Surveillance and Preventive Maintenance Program, One-Time Inspection Program, Systems Monitoring Program and Water Chemistry Control Program. The staff's evaluation of these programs is documented in SER Sections 3.0.3.2.4, 3.0.3.2.6, 3.0.3.3.1, 3.0.3.2.13, 3.0.3.3.2, and 3.0.3.2.20, respectively.

The applicant proposed to manage cracking due to SCC of stainless steel material for component types of valve bodies, instrument valve assemblies, flow elements, heat exchangers, piping/fittings, and restricting orifices exposed to treated water with temperatures greater than 120 °F environment using the Water Chemistry Control Program and One-Time Inspection Program, to provide confirmation of effectiveness.

The staff reviewed the applicant's Water Chemistry Control Program and One-Time Inspection Program and its evaluations are documented in SER Sections 3.0.3.2.20 and 3.0.3.2.13, respectively.

On the basis of its review of the applicant's programs, and plant-specific and industry operating experience, the staff found that loss of material and cracking due to SCC for components in the main and auxiliary steam system are effectively managed. Therefore, the staff found that management of loss of material and cracking due to SCC in the main and auxiliary steam system using these programs is acceptable.

The applicant proposed to manage loss of material due to FAC/erosion - corrosion of carbon and low-alloy steels materials for component type of flow elements, piping and fittings, steam traps, heat exchangers, tanks, and valve bodies exposed to treated water - secondary (T>120 °F)(internal) by using the Flow-Accelerated Corrosion Program and Water Chemistry Control Program.

The staff reviewed the applicant's Flow-Accelerated Corrosion Program and Water Chemistry Control Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.11 and 3.0.3.2.20, respectively.

On the basis of its review of the applicant's programs, and plant-specific and industry operating experience, the staff found that loss of material due to FAC/erosion-corrosion for components in the main and auxiliary steam system are effectively managed using the Flow-Accelerated Corrosion Program and Water Chemistry Control Program. Therefore, the staff found that management of loss of material due to FAC in the main and auxiliary steam system using these programs is acceptable.

3.4.2.3.3 Feedwater and Condensate System - Aging Management Evaluation - Table 3.4.2-2

The staff reviewed LRA Table 3.4.2-2, as modified by letter dated April 29, 2005, which summarizes the results of AMR evaluations for the feedwater and condensate system component groups.

The feedwater and condensate system experiences loss of material of cast iron, carbon and low-alloy steel, stainless steel, and CASS for the following component types:

- CS components
- fasteners and bolting
- flow elements
- instrument valve assemblies
- level gauges
- piping and fittings
- pump casing
- steam traps
- tanks
- valve bodies

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- treated water - secondary (T>120 °F)(internal)
- treated water - secondary (T<120 °F)(internal)
- indoor - no air conditioning (external)
- containment (external)

The applicant proposed to manage the feedwater and condensate system loss of material aging effects by using the Bolting Integrity Program, Boric Acid Corrosion Program, Water Chemistry Control Program, One-Time Inspection Program, and Systems Monitoring Program. The staff's evaluation of these programs is documented in SER Sections 3.0.3.2.4, 3.0.3.2.6, 3.0.3.2.20, 3.0.3.2.13 and 3.0.3.3.2, respectively.

The applicant proposed to manage loss of material due to FAC/erosion - corrosion of carbon and low-alloy steel material for component types of flow elements, valve bodies, and piping and fittings, exposed to treated water - secondary (T>120 °F)(internal), by using the Water Chemistry Control Program and Flow-Accelerated Corrosion Program.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to FAC/erosion - corrosion in the feedwater and condensate system are effectively managed using the Water Chemistry Control Program and Flow-Accelerated Corrosion Program. On this basis, the staff found that management of loss of material due to FAC/erosion - corrosion in the feedwater and condensate system is acceptable.

The applicant proposed to manage cracking due to SCC of stainless steel material for component types of flow elements, instrument valve assemblies, piping and fittings, and valve bodies, exposed to treated water - secondary (T>120 °F)(internal) using the Water Chemistry Control Program, and One-Time Inspection Program.

On the basis of its review of the applicant's programs, and plant-specific and industry operating experience, the staff found that cracking due to SCC in the feedwater and condensate system is effectively managed using the Water Chemistry Control Program and One-Time Inspection Program. Therefore, the staff found that management of cracking due to SCC in the feedwater and condensate system using these programs is acceptable.

3.4.2.3.4 Auxiliary Feedwater System AMR Results - 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 auxiliary feedwater system component groups.

The auxiliary feedwater system experiences loss of material of carbon and low-alloy steel, cast iron, CASS, copper alloy (Zn<15%), aluminum, and stainless steel for the following component types:

- accumulators and cylinders
- CS components
- fasteners and bolting
- flow elements

- heat exchanger
- instrument valve assemblies
- piping and fittings
- pump casing
- restricting orifices
- tanks
- turbine casing
- valve bodies
- valve operator

For those components requiring staff review, the environments are listed below:

- borated water leaks (external)
- treated water - secondary (T>120 °F)(internal)
- treated water - secondary (T<120 °F)(internal)
- indoor - no air conditioning (external)
- containment (external)
- raw water - stagnant (internal)
- oil and fuel oil (internal)

The applicant proposed to manage the auxiliary feedwater system loss of material aging effects by using the Bolting Integrity Program, Boric Acid Corrosion Program, Water Chemistry Control Program, One-Time Inspection Program, Systems Monitoring Program, Open-Cycle Cooling (Service) Water System Surveillance Program, Tank Internal Inspection Program, and Periodic Surveillance and Preventive Maintenance Program. The staff's evaluations of these programs are documented in SER Sections 3.0.3.2.4, 3.0.3.2.6, 3.3.2.20, 3.0.3.2.13, 3.0.3.3.2, 3.0.3.2.14, 3.0.3.3.3, and 3.0.3.3.1, respectively.

The applicant proposed to manage loss of heat transfer due to fouling on stainless steel on component type of heat exchangers by using the Periodic Surveillance and Preventive Maintenance Program. In addition, it proposed to manage loss of material due to FAC/erosion-corrosion on stainless steel and carbon and low-alloy steel in component type of valve bodies, pipings and fittings by using the Flow-Accelerated Corrosion Program and Water Chemistry Control Program. The staff's evaluation of these programs are evaluated in SER Sections 3.0.3.2.11 and 3.0.3.2.20, respectively.

The staff's review of LRA Table 3.4.2-3 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.

<u>RAI 3.4-1</u>. In LRA Table 3.4.2-3, the stainless steel heat exchangers, with either heat transfer or pressure boundary as the intended function, are identified with only internal environments and associated aging effects. The external environment is listed as "not applicable." In RAI 3.4-1, dated July 30, 2004, the staff requested the applicant to explain why no external environments and associated aging effects are identified for these components.

In its letter, dated August 30, 2004, the applicant stated that due to the way the license renewal database was developed and used, tubing assets were identified as two separate components (tubing ID and tubing OD). This allowed the user to designate an internal environment for each (tubing ID and tubing OD), but since the database required each component to have both an internal and external environment, the external environment would then be documented as "not applicable." The applicant noted that in LRA Table 3.4.2-3, there is a heat exchanger material type with two different internal environments, which is reflective of the environments for the ID and OD of the tubing. Because the tubing has a pressure boundary intended function in addition to the heat transfer function, this same information was duplicated for the pressure boundary intended function line items.

The applicant also stated that the only heat exchanger components that have a heat transfer intended function are the tubes. External environments (indoor - no air conditioning, outdoor, etc.) would only apply to the shell of the heat exchanger. The shell only has a pressure boundary function; therefore, the shell and its external environment are not identified under the heat transfer intended function. Additionally, the shell is typically made of a different material than the tubes and, therefore, would not be represented by the same line item as the tubing in the LRA. In LRA Table 3.4.2-3, the heat exchanger shell is cast iron and has an "indoor - no air conditioning" external environment. The applicant stated that the System Monitoring Program applies to the shell.

The staff considered the applicant's response to be adequate in explaining the relationship among components, material, and environments listed in LRA Table 3.4.2-3. The staff's concern described in RAI 3.4-1 is resolved.

<u>RAI 3.4-2</u>. In the first quarter of 2003, PBNP entered the Multiple/Repetitive Degraded Cornerstone Column in the Action Matrix of NRC Inspection Manual Chapter 0305, "Operating Reactor Assessment Program," as a result of a high significance (Red) inspection finding involving the potential for a common mode failure of the auxiliary feedwater system following a loss of the instrument air system. A second inspection finding (Yellow for Unit 1 and Red for Unit 2) was subsequently identified which involved the potential common mode failure of the auxiliary feedwater pumps due to plugging of the recirculation line pressure reduction orifices. In view of the aforementioned inspection findings and the subsequent corrective actions for the two auxiliary feedwater issues, in RAI 3.4-2, dated July 30, 2004, the staff requested the applicant to address the following questions in the context of the license renewal application:

(1) Clarify whether the instrument air system (or portions of the system) and the recirculation line pressure reduction orifices are within the scope of license renewal, and if appropriate AMPs have been identified to manage the components. If not, the staff requested the applicant to explain why they are out of scope.

(2) For aging management evaluation as summarized in LRA Table 3.4.2-3 for the auxiliary feedwater system, discuss any impact on the scoping of mechanical components and the AMR performed for the affected components, as a result of the recent physical modifications made to resolve the auxiliary feedwater pump room Appendix R issues.

In its response, dated August 30, 2004, the applicant stated that portions of the instrument air system, including cylinders, tanks, tubing, and valves associated with air side of the recirculation valves on all auxiliary feedwater pumps are within the scope of license renewal. In addition, all of the pressure reduction orifices (1RO-4003, 2RO-4003, RO-4008, and RO-4015) and their associated recirculation lines back to the condensate storage tanks are within the scope of license renewal. The applicant stated that these components are represented in LRA Table 3.4.2-3 under the following component types: accumulators/cylinders, pipes and fittings, restricting orifices, tanks, valve bodies, and valve operators. Also, as shown in LRA Table 3.4.2-3, appropriate AMPs were selected based on aging effects identified for each material/environment combination.

The applicant further stated that recent physical modifications to the auxiliary feedwater pump room are not represented in the LRA because they were not in place at the time their 'snapshot' of component data was taken to perform license renewal activities. However, these modifications will be included in its LRA annual update, and appropriate AMPs and activities would then be identified for these new components. Based on the information provided by the applicant, the staff determined that the affected modifications in the auxiliary feedwater pump room will be managed through an established LRA annual update activity.

The staff found that the applicant's response provides assurance that the affected auxiliary feedwater system components are within the scope of license renewal and being adequately managed in the LRA. The staff's concerns described in RAI 3.4-2 are resolved.

The staff reviewed the LRA, industry operating experience, and RAI responses. The staff concluded that the applicant adequately identified the aging effects, and the AMPs credited for managing the aging effects, for the auxiliary feedwater. The staff concluded 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 54.21(a)(3).

3.4.3 Conclusion

On the basis of its review, the staff concluded that the applicant had demonstrated that the aging effects associated with the steam and power conversion components 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 FSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the steam and power conversion, as required by 10 CFR 54.21(d).

3.5 Aging Management of Containments, Structures, and Components Supports

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

- Units 1 and 2 containment building structure
- control building structure
- circulating water pumphouse structure
- diesel generator building structure
- Units 1 and 2 facade structure
- primary auxiliary building structure
- Units 1 and 2 turbine building structure
- yard structures
- cranes, hoists, and lifting devices
- component supports commodity group
- fire barrier commodity group
- 13.8 KV switchgear building structure

- fuel oil pumphouse structure
- gas turbine building structure

3.5.1 Summary of Technical Information in the Application

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

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine if the applicant had provided sufficient information to demonstrate that the effects of aging for the containment, structures and components supports 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).

Also, the staff performed an onsite audit 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 AMPs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluations are documented in the staff's PBNP audit and review report and summarized in SER Section 3.5.2.1.

The staff also performed an onsite audit of those AMRs that are consistent with the GALL Report and for which further evaluation is recommended. The staff verified that the applicant's further evaluations were consistent with the acceptance criteria in NUREG-1800 Section 3.5.2.2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated July 2001. The staff's audit evaluations are documented in the staff's PBNP audit and review report and summarized in SER Section 3.5.2.2.

The staff performed an onsite audit and conducted a technical review of the remaining AMRs that were not consistent with the GALL Report. The audit and technical review included evaluating whether all plausible aging effects had been identified and the aging effects listed were appropriate for the combination of materials and environments specified. The staff's audit evaluations are documented in the staff's PBNP audit and review report and 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 FSAR 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 system 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 System Components in the GALL Report

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
PWR Containment				
Penetration sleeves, bellows, and dissimilar metal welds (Item Number 3.5.1-01)	Cumulative fatigue damage (CLB fatigue analysis exists)	TLAA evaluated in accordance with 10 CFR 54.21(c)	TLAA	This TLAA is evaluated in Section 4.3, Metal Fatigue (See Section 3.5.2.2.6)
Penetration sleeves, bellows, and dissimilar metal welds (Item Number 3.5.1-02)	Cracking due to cyclic loading, or crack initiation and growth due to SCC	Containment ISI and containment leak rate test	Not Applicable	Not Applicable (See Section 3.5.2.2.7)
Penetration sleeves, bellows, and dissimilar metal welds (Item Number 3.5.1-03)	Loss of material due to corrosion	Containment ISI and containment leak rate test	Inservice Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.1)
Personnel airlock and equipment hatch (Item Number 3.5.1-04)	Loss of material due to corrosion	Containment ISI and containment leak rate test	Inservice Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.1)
Personnel airlock and equipment hatch (Item Number 3.5.1-05)	Loss of leak tightness in closed position due to mechanical wear of locks, hinges and closure mechanism	Containment leak rate test and plant technical specifications	Inservice Inspection Program	Consistent with GALL, 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
Seals, gaskets, and moisture barriers (Item Number 3.5.1-06)	Loss of sealant and leakage through containment due to deterioration of joint seals, gaskets, and moisture barriers	Containment ISI and containment leak rate test	Inservice Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.1)
PWR Concrete (Reinforced and Prestressed) and Steel Containment				
Concrete elements: foundation, dome, and wall (Item Number 3.5.1-07)	Aging of accessible and inaccessible concrete areas due to leaching of calcium hydroxide, aggressive chemical attack, and corrosion of embedded steel	Containment ISI	Inservice Inspection Program, Structures Monitoring Program	Consistent with GALL, which recommends further evaluation. (See Section 3.5.2.2.1)
Concrete elements: foundation (Item Number 3.5.1-08)	Cracks, distortion, and increases in component stress level due to settlement	Structures monitoring	Structures Monitoring Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.2.2)
Concrete elements: foundation (Item Number 3.5.1-09)	Reduction in foundation strength due to erosion of porous concrete sub-foundation	Structures monitoring	Structures Monitoring Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.2.2)
Concrete elements: foundation, dome, and wall (Item Number 3.5.1-10)	Reduction of strength and modulus due to elevated temperature	Plant-specific	Inservice Inspection Program, Structures Monitoring Program	Consistent with GALL, which recommends further evaluation. (See Section 3.5.2.2.3)
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	This TLAA is evaluated in Section 4.5, Loss of Preload. (See Section 3.5.2.2.5)
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 and containment leak rate test	Inservice Inspection Program, Boric Acid Corrosion Program	Consistent with GALL, which recommends further evaluation. (See Section 3.5.2.2.4)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
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	Structures Monitoring Program, Inservice Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.1)
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	Inservice Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.1)
Concrete elements: foundation, dome, and wall (Item Number 3.5.1-16)	Scaling, cracking, and spalling due to freeze-thaw; expansion and cracking due to reaction with aggregate	Containment ISI	Inservice Inspection Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.1)
Class I Structures				
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	Structures Monitoring Program, Boric Acid Corrosion Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.2.8)
Groups 1-3, 5, and 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	Structures Monitoring Program	Consistent with GALL, which recommends further evaluation. (See Section 3.5.2.2.9)
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 or FERC/US Army Corps of Engineers dam inspections and maintenance	Structures Monitoring Program	Consistent with GALL, 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
Group 5: liners (Item Number 3.5.1-23)	Crack initiation and growth from SCC and loss of material due to crevice corrosion	Water Chemistry Control Program and monitoring of spent fuel pool water level	Water Chemistry Control Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.1)
Groups 1-3, 5, and 6: all masonry block walls (Item Number 3.5.1-24)	Cracking due to restraint, shrinkage, creep, and aggressive environment	Masonry wall	Structures Monitoring Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.1)
Groups 1-3, 5,and 7-9: foundation (Item Number 3.5.1-25)	Cracks, distortion, and increases in component stress level due to settlement	Structures monitoring	Structures Monitoring Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.2.2)
Groups 1-3 and 5-9: foundation (Item Number 3.5.1-26)	Reduction in foundation strength due to erosion of porous concrete sub-foundation	Structures monitoring	Structures Monitoring Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.2.2)
Groups 1-5: concrete (Item Number 3.5.1-27)	Reduction of strength and modulus due to elevated temperature	Plant-specific	Inservice Inspection Program, Structures Monitoring Program	Consistent with GALL, which recommends further evaluation. (See Section 3.5.2.2.3)
Groups 7 and 8: liners (Item Number 3.5.1-28)	Crack Initiation and growth due to SCC; Loss of material due to crevice corrosion	Plant-specific	Not Applicable	Not Applicable
Component Supports				
All groups support members: anchor bolts, concrete surrounding anchor bolts, welds, grout pads, bolted connections, etc. (Item Number 3.5.1-29)	Aging of component supports	Structures monitoring	Structures Monitoring Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.2.10)

Component Group	Aging Effect/ Mechanism	AMP in GALL Report	AMP in LRA	Staff Evaluation
Groups B.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 4.3, Metal Fatigue (See section 3.5.2.2.11)
All groups support members: anchor bolts and welds (Item Number 3.5.1-31)	Loss of material due to boric acid corrosion	Boric acid corrosion	Boric Acid Corrosion Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.1)
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	Inservice Inspection Program, Structures Monitoring 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	Bolting Integrity Program	Consistent with GALL, which recommends no further evaluation. (See Section 3.5.2.1)

The staff's review of the PBNP Containments, Structures, and Components Supports and associated components 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 Components 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 Components 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 Components Supports that the applicant indicated are not consistent with the GALL Report or are 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 Components 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 Units 1 and 2

containment building structure, control building structure, circulating water pumphouse structure, diesel generator building structure, Units 1 and 2 facade structure, primary auxiliary building structure, Units 1 and 2 turbine building structure, yard structures, cranes, hoists, and lifting devices, component supports commodity group, fire barrier commodity group, 13.8 KV switchgear building structure, fuel oil pumphouse structure, and gas turbine building structure:

- ASME Section XI, Subsections IWE and IWL Inservice Inspection Program
- ASME Section XI, Subsection IWF Inservice Inspection Program
- Boraflex Monitoring Program
- Boric Acid Corrosion Program
- Fire Protection Program
- Periodic Surveillance and Preventive Maintenance Program
- Structures Monitoring Program
- Water Chemistry Control Program

Staff Evaluation. In LRA Tables 3.5.2-1 through 3.5.2-14, the applicant provided a summary of AMRs for the Units 1 and 2 containment building structure, control building structure, circulating water pumphouse structure, diesel generator building structure, Units 1 and 2 facade structure, primary auxiliary building structure, Units 1 and 2 turbine building structure, yard structures, cranes, hoists, and lifting devices, component supports commodity group, fire barrier commodity group, 13.8 KV switchgear building structure, fuel oil pumphouse structure, and gas turbine building structure 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's audit of those AMRs with Notes A through E, 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, although different, is 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, although different, is 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 aging management program 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 PBNP 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 have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the containments, structures, and component supports components that are subject to an AMR. On the basis of its review, 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 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 found 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 found 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

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

In LRA Section 3.5.2.2 the applicant provided further evaluation of aging management as recommended by the GALL Report for Units 1 and 2 containment building structure, control building structure, circulating water pumphouse structure, diesel generator building structure, Units 1 and 2 facade structure, primary auxiliary building structure, Units 1 and 2 turbine building structure, yard structures, cranes, hoists, and lifting devices, component supports commodity group, fire barrier commodity group, 13.8 KV switchgear building structure, fuel oil pumphouse structure, and gas turbine building structure. The applicant provided information concerning how it will manage the following aging effects:

PWR Containments:

- aging of inaccessible concrete areas;
- cracking, distortion, and increase in component stress levels due to settlement; reduction of foundation strength due to erosion of porous concrete subfoundations, if not covered by the 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; and
- cracking due to cyclic loading and SCC.

Class I Structure:

- aging of structures not covered by the Structures Monitoring Program; and
- aging management of inaccessible areas.

Component Supports:

- aging of supports not covered by the Structures Monitoring Program; and
- cumulative fatigue damage due to cyclic loading.

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 3.5.3.2. Details of the staff's audit are documented in the staff's PBNP audit and review report.

3.5.2.2.1 PWR Containments

The staff reviewed LRA Section 3.5.2.2.1 against the criteria in SRP-LR Section 3.5.2.2.1, which addresses several areas discussed below.

Aging of Inaccessible Concrete Areas. The staff reviewed LRA Section 3.5.2.2.1.1 against the criteria in SRP-LR Section 3.5.2.2.1.1. In LRA Section 3.5.2.2.1.1, the applicant addressed aging of inaccessible concrete areas for the containment.

The ASME Code Subsection IWL exempts from examination portions of the concrete containment that are inaccessible (*e.g.*, concrete covered by liner, foundation material, or backfill, or obstructed by adjacent structures or components). However, 10 CFR 50.55a(b)(2)(ix) requires that the applicant evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to inaccessible areas.

The AMP recommended by the GALL Report for managing the aging of the accessible portions of the containment structures is GALL AMP XI.S2, "ASME Section XI, Subsection IWL." The applicant addressed this with ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program. The staff reviewed the applicant's ASME Code Section XI, Subsection IWE and IWL ISI Program and its evaluation is addressed in SER Section 3.0.3.2.2.

In GALL Report, Volume 2, Chapter II, Table A1, as updated by ISG-03 dated November 23, 2001, "Proposed Revision of Chapters II and III of Generic Lessons Learned (GALL) Report on Aging Management of Concrete Elements," states that further evaluation is recommended for managing the aging effects for containment concrete components located in inaccessible areas for the aging mechanisms of (1) freeze-thaw, (2) leaching of calcium hydroxide, (3) aggressive chemical attack, (4) reaction with aggregates, or (5) corrosion of embedded steel. Possible aging effects for containment concrete structural components due to these five aging mechanisms are cracking, change in material properties, and loss of material.

(1) Freeze-thaw. SRP-LR Section 3.5.2.2.1.1 does not address freeze-thaw as an aging mechanism for concrete containments because no further evaluation is recommended in the GALL Report. However, ISG-03 clarifies the staff position that further evaluation is appropriate if the applicant's facility is subject to moderate to severe weathering conditions unless the concrete meets certain specifications and subsequent inspections have confirmed that the aging mechanism has not caused degradation of the concrete.

The applicant stated that Units 1 and 2 are located in a severe weathering region. In LRA Table 3.5.0-1, Part (11), the applicant stated that construction of the containment was performed under a contract containing concrete specifications. The specifications specified concrete entrained air content and water-to-cement ratio which meet the recommendations contained in the American Concrete Institute (ACI) specification ACI 318 63, "Building Code Requirements for Reinforced Concrete." Therefore, loss of material and cracking due to freeze-thaw is not an applicable aging mechanism requiring management. Additionally, the entire containment structures are protected from the weather by the facade structure. However, the applicant stated that the inspections performed in accordance with the requirements of the ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program would detect freeze-thaw aging effects during the period of extended operation, should they occur.

During the audit, the staff interviewed members of the applicant's technical staff and reviewed relevant operating experience to confirm that loss of material from freeze-thaw has not been observed, either through ASME Code Section XI, Subsection IWE and

IWL Inservice Inspection Program or the Structures Monitoring Program. The staff agreed that the concrete specification applied at PBNP would be expected to protect against the freeze-thaw aging effects. The staff's review of operating experience did not identify any history of freeze-thaw aging effects. During these discussions, the applicant stated that, even though they do not believe freeze-thaw is an active aging mechanism at PBNP, the inspections performed in accordance with the requirements of the ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program, would detect freeze-thaw aging effects during the period of extended operation, should they occur. The staff agrees that this program adequately manages the aging effect of freeze-thaw.

On the basis of its review, the staff found that, based on the concrete specifications for the containment, in conjunction with the physical protection provided to the containment by the facade structure, the applicant is consistent with the GALL Report, Chapter II, Containment Structures, Item A1.1-a, as updated by ISG-03, and has demonstrated that loss of material and cracking due to freeze-thaw will be adequately managed.

(2) Leaching of calcium hydroxide. SRP-LR Section 3.5.2.2.1.1 states that cracking, spalling, and increases in porosity and permeability due to leaching of calcium hydroxide could occur in inaccessible areas of PWR concrete and steel containments. The GALL Report, as updated by ISG-03, recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria cannot be satisfied.

The GALL Report, Chapter II, Containment Structures, Item A1.1-b states that leaching of calcium hydroxide becomes significant only if the concrete is exposed to flowing water. Even if reinforced concrete is exposed to flowing water, such leaching is not likely if the concrete is constructed to ensure that it is dense, well-cured, has low permeability, and that cracking is well controlled. Cracking is controlled through proper arrangement and distribution of reinforcing bars. All of the above characteristics are assured if the concrete was constructed with the guidance of ACI 201.2R-77, "Guide to Durable Concrete."

In LRA Table 3.5.0-1, Part (8), the applicant stated that its concrete specification met the intent of ACI 201.2R and that the containment is not exposed to flowing water. Also, the containment structures are protected from the weather by the facade structure.

On the basis of its review, the staff found that, based on the concrete specifications for the containment, lack of exposure to flowing water, and the protection from the weather provided to the containment by the facade structure, the applicant is consistent with the GALL Report, Chapter II, Containment Structures, Item A1.1-b, as updated by ISG-03, and has demonstrated that cracking, spalling, and increases in porosity and permeability due to leaching of calcium hydroxide will be adequately managed.

(3) Aggressive chemical attack. SRP-LR Section 3.5.2.2.1.1 states that cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack could occur in inaccessible areas of PWR concrete and steel containments. The GALL Report, as updated by ISG-03, recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL Report cannot be satisfied.

The GALL Report, Chapter II, Containment Structures, Item A1.1-c, states that for below-grade exterior reinforced concrete (basemat, embedded walls), a plant-specific aging management program is required only if the below-grade environment is aggressive (pH less than 5.5, chlorides greater than 500 ppm, or sulfates greater than 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. ISG-03 also states that a plant-specific aging management program is recommended for inaccessible areas if the below-grade environment is found to be aggressive.

The applicant stated that the below-grade/lake-water environment is not aggressive. Also, the applicant stated that its Structure Monitoring Program requires periodic monitoring of ground/lake water to confirm chemistry remains nonaggressive.

The staff's review of LRA Section 3.5 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.

RAI 3.5-13. In LRA Section 3.5.2.2.1.1, the applicant stated that concrete degradation in air due to aggressive rainwater is insignificant and that the below-grade/lake water environment is nonaggressive. In RAI 3.5-13, dated March 30, 2005, the staff requested the applicant to provide sufficient data to support this statement.

Furthermore, during the review, the staff was unable to identify how the LRA addresses the items described in ISG-03. The staff requested the applicant to provide detailed information as to how its AMRs address all the items described in ISG-03.

During conversations with the staff, the applicant agreed to provide its most recent data with respect to the below-grade/lake water. Additionally, the applicant committed to provide a table detailing how the AMRs satisfy all the items described in ISG-03. This was identified as confirmatory item (CI) 3.5-13.

In its response to CI 3.5-13, by letter dated June 9, 2005, the applicant provided its ground water environment monitoring data and an explanation of where the LRA addresses each of the provisions of ISG-03. In addition, the applicant clarified the percentage of entrapped air in the containment concrete. As part of the response, the applicant committed to monitoring ground water chemistry (pH, chlorides, sulfates) at least once every 5 years.

The staff found the applicant's response to RAI 3.5-13 and its commitment to monitor ground water chemistry to be consistent with the guidance of the GALL Report and ISG-03. The staff's concerns are resolved; therefore, CI 3.5-13 is closed.

On the basis of its review, the staff found that, based on the nonaggressive below-grade/lake-water environment and the periodic confirmatory water monitoring, the application is consistent with the GALL Report, Chapter II, Containment Structures, Item A1.1-c, as updated by ISG-03, and demonstrated that cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack will be adequately managed.

(4) Reaction with Aggregates. SRP-LR Section 3.5.2.2.1.1 does not address cracking due to reaction with aggregates as an aging mechanism for concrete containments because no further evaluation is recommended in the GALL Report. However, ISG-03 clarifies the staff position that further evaluation is appropriate if investigations, tests, or examinations have demonstrated that the aggregates are reactive.

ISG-03 recommends using GALL AMP XI.S6, "Structures Monitoring Program," to manage aggregate reactions in accessible areas. ISG-03 states that inspections and 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, the ISG states that 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 Table 3.5.0-1, Part (8), the applicant stated that the containment concrete specifications specified testing of aggregate for potential reactivity in accordance with ASTM C227 and C295. Based on the criteria of ISG-03 and the aggregate tests, which demonstrated the lack of reactive aggregate, the staff agreed that evaluation of inaccessible areas is not needed at PBNP.

On the basis of its review, the staff found that, based on the testing of aggregate for potential reactivity performed during construction, the applicant is consistent with the GALL Report, Chapter II, Containment Structures, Item A1.1-d, as updated by ISG-03, and has demonstrated that cracking due to reaction with aggregates will be adequately managed.

(5) Corrosion of embedded steel. SRP-LR Section 3.5.2.2.1.1 states that cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel could occur in inaccessible areas of PWR concrete and steel containments. The GALL Report, as updated by ISG-03, recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL Report cannot be satisfied.

The GALL Report, Chapter II, Containment Structures, Item A1.1-e, states that for below-grade exterior reinforced concrete (basemat, embedded walls), a plant-specific aging management program is required only if the below-grade environment is aggressive (pH less than 5.5, chlorides are greater than 500 ppm, or sulfates are greater than 1500 ppm). Examination of representative samples of below-grade concrete, when excavated for any reason, is to be included as part a plant-specific program. ISG-03 also states that a plant-specific aging management program is required for inaccessible areas if the below-grade environment is found to be aggressive.

In LRA Section 3.5.2.2.1.1, the applicant stated that the below-grade/lake-water environment is not aggressive. Also, the applicant stated that its Structure Monitoring Program requires periodic monitoring of ground/lake water to confirm that the water chemistry remains nonaggressive.

The staff found that based on the nonaggressive below-grade/lake-water environment and the periodic confirmatory water monitoring, the application is consistent with the GALL Report, Chapter II, Containment Structures, Item A1.1-e, as updated by ISG-03. The applicant demonstrated that cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel will be adequately managed.

The staff reviewed the results of the applicant's AMR for inaccessible concrete areas. On the basis of its review and as discussed above, the staff found that the applicant had appropriately evaluated AMR results involving management of aging of inaccessible concrete areas for the containment, as recommended in the GALL Report and ISG-3. Since the applicant's AMR results are otherwise consistent with 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>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</u>. The staff reviewed LRA Section 3.5.2.2.1.2 against the criteria in SRP-LR Section 3.5.2.2.1.2.

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 PWR concrete and steel containments. SRP-LR Section 3.5.2.2.1.2 also states that reduction of foundation strength due to erosion of porous concrete subfoundations could occur in all types of PWR containments.

The GALL Report recommends no further evaluation if these activities are included in the scope of the applicant's Structures Monitoring Program.

In LRA Section 3.5.2.2.1.2, the applicant stated that all structures are founded on either spread footings, basemats, or basemats with steel foundation piles that are driven to refusal. Settlement monitoring and structural inspections indicate no visible evidence of uneven or excessive settlement since construction of the station. In addition, in LRA Section 3.5.2.2.1.2, the applicant stated that structure foundations were constructed of normal concrete and not the porous type, and that the foundations are not subject to flowing water. The applicant also stated that its Structures Monitoring Program monitors for settlement, cracking, and distortions.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. On the basis of its review, the staff found that, based on the foundation designs used at PBNP and on the absence of porous concrete in subfoundations, the applicant satisfied the specific criteria in the GALL Report and demonstrated that cracking, distortion, and increase in component stress level due to settlement and reduction of foundation strength due to erosion of porous concrete subfoundations will be adequately managed.

On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving management of cracking, distortion, and increase in component stress level due to settlement; and reduction of foundation strength due to erosion of porous concrete subfoundations, if not covered by Structures Monitoring Program for the containment, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Reduction of Strength and Modulus of Concrete Structures Due to Elevated Temperature. The staff reviewed LRA Section 3.5.2.2.1.3 against the criteria in SRP-LR Section 3.5.2.2.1.3.

In LRA Section 3.5.2.2.1.3, the applicant addressed reduction of strength and modulus of concrete structures due to elevated temperature in containments.

SRP-LR Section 3.5.2.2.1.3 states that reduction of strength and modulus of elasticity due to elevated temperatures could occur in PWR concrete and steel containments. The GALL Report calls for a plant-specific aging management program and recommends further evaluation if any portion of the concrete containment components exceeds specified temperature limits (*i.e.*, general area temperature of 66 °C (150 °F) and local area temperature of 93 °C (200 °F)).

The applicant stated that for plant areas of concern, temperatures are normally maintained below the specified limits. As documented in the audit and review report, the applicant stated that, by design, containment concrete should not be exposed to temperatures above FSAR specified limits; however, the applicant stated that four Unit 2 containment penetrations associated with the main steam and feedwater systems concrete may be exposed to temperatures above the specified limits. This Unit 2 nonconforming condition is captured and addressed by the corrective action program. Currently, the status of the main steam penetrations is operable but degraded. The applicant further stated that, as part of the plant's existing corrective action process, the main steam penetrations would be inspected and restored to original design conditions during the next Unit 2 refueling outage, which was planned for Spring 2005.

The applicant stated that it included susceptible components within the scope of the Structures Monitoring Program and the ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program, to monitor for loss of material, cracks, and changes in material properties.

The staff reviewed the applicant's Structures Monitoring Program and ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program, and its evaluations are documented in SER Sections 3.0.3.2.19 and 3.0.3.2.2, respectively. The staff found that, based on the design of the hot penetration areas, in combination with the resolution of the corrective action associated with concrete that operated at an elevated temperature and continuing monitoring under the Structures Monitoring Program and ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program, any reduction of strength and modulus of elasticity due to elevated temperatures in PWR concrete will be adequately managed.

The staff's review of LRA Section 3.5 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.

RAI 3.5-3. In LRA Section 3.5.2.2.1.3, and LRA Table 3.5.0-1, Item 9 (plant-specific response to WCAP-14756-A), the applicant asserted that the concrete temperatures around the high-energy piping penetrations are well below the established threshold value of 200 °F.

However, the applicant's report (PB OPR 000096) indicated that the concrete temperatures around the main steam lines were found to be about 380 °F for an unknown period of time. The staff noted that such sustained temperatures not only affect the concrete compressive strength and its elastic modulus, but also accentuate the concrete creep and relaxation of prestressing tendons located in the vicinity of high temperature areas. The net effect could lower tendon forces in these areas. In RAI 3.5-3, dated July 27, 2004, the staff requested the applicant to provide information regarding the actions taken to (1) control the concrete temperatures in these areas, (2) assess the condition of the concrete in these areas, (3) assess the condition of penetration liners, and (4) monitor the prestressing forces in the affected tendons. Also, the applicant was requested to discuss the consequences of the sustained high temperatures on the concrete and the prestressing tendons during the extended period of operation.

In its response, dated August 26, 2004, the applicant stated that the issues related to Items 1, 2, and 3, above are captured as part of the non-conforming condition in the corrective action program, namely: (1) CAP 51854, N2 MS Line Containment Penetration Concrete Temp Above FSAR Specified Allowable dated 11/15/03, (2) OPR 96, N2 MS Line Containment Penetration Concrete Temp Above FSAR Specified Allowable dated 11/16/03, (3) OBD (operable but degraded) 124, U2 MS Line Cont Pen Concrete Temp Above FSAR Specified Allowable - Action Plan dated 11/18/03, (4) OBD 134, Open & Inspect 2 Main Steam & 2 Main Feedwater Penetrations of Unit 2 Containment dated 12/17/03.

With respect to RAI Item 4, the applicant stated that the Tendon Surveillance Program is in accordance with the ASME Code Subsection IWL, 1992 Edition through 1992 Addenda, which includes the limitations and modification requirements endorsed by 10 CFR 50.55a, and RG 1.35, Revision 3, dated July 1990. The program also includes tendon prestressing force inservice inspection and monitoring of time-dependent and other losses. The lift-off monitoring test monitors all losses including relaxation of prestressing steel and effects of variations in temperatures. To date, comparison of the measured tendon forces against the predicted forces at the time of the lift-off has been well above the lower predicted limit. The applicant further clarified that the non-conforming high temperature main steam line containment penetration could have an effect on the hoop tendons. This condition was evaluated and documented in Operability Recommendation OPR 96. The applicant noted that the tendon's exposure to the slightly higher temperature, has occurred over a relatively short length of the tendon and it was determined to present a negligible effect. The applicant indicated that consideration will be given to include one of these random tendons for testing during the next regularly scheduled surveillance test for that unit.

During the current license period, the applicant is addressing this issue through operability evaluations and additional inspections. The staff will pursue this issue as a current licensing concern to ascertain that the licensee will formalize a corrective action that would ensure the effects of high temperatures on the concrete and the prestressing tendons are appropriately addressed. The staff found that the ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program would provide the assurance of the containment integrity during the period of extended operation. On the basis of the above discussion, the staff's concerns described in RAI 3.5-3 are resolved.

RAI 3.5-5. The evaluation in LRA Section 3.5.2.2.1.3 associated with LRA Table 3.5.1 line Item 3.5.1-27 indicated that the reactor cavity cooling subsystem maintains acceptable ambient temperature at the primary shield and reactor vessel support structure. In RAI 3.5-5, dated

July 27, 2004, the staff requested the applicant to provide the following information related to the concrete temperatures and monitoring activities in the primary shield and reactor vessel support areas for Units 1 and 2:

(1) Operating experience related to the functionality of the reactor cavity cooling subsystem including a range of temperatures maintained between the reactor vessel and the primary shield wall, and at the reactor vessel support, and means of monitoring these temperatures;

(2) If a separate cooling system is installed to cool the primary shield wall concrete, the operating experience related to the functionality of this system, and means used to monitor the primary shield concrete temperatures; and

(3) A summary of the results of the last inspection performed in these areas, such as concrete cracking, spalling, pop-outs, etc.

In its response, dated August 26, 2004, the applicant stated that in response to Item (1), the primary concrete shielding and its temperature are discussed on FSAR page 11.6-3. The reactor cavity cooling system (VNRC) consists of two fans and two cooling coils (one per fan). The fans draw containment air over the service water cooling coils where the air is dehumidified and cooled. The fans discharge the air into a common duct which supplies cooled air to the reactor vessel annulus for cooling the primary shield wall and nuclear instrumentation immediately external to the reactor. Normally, one fan and cooling coil set is in operation with the other set in standby. The applicant further clarified that the VNRC is not within the scope of license renewal. In addition, the applicant stated that the reactor cavity cooling fans are started manually from the control room. Only one fan and service water cooler is required for operation as each fan and cooler are sized for 100 percent capacity. Service water flow through the coolers is manually controlled. A flow switch on the fan outlet indicates and alarms low flow conditions on the control room control board. Temperature elements located in various areas provide temperature information to the plant process computer system.

In response to item (2), the applicant stated that there is no separate cooling system employed other than the reactor cavity cooling system. In response to item (3), the applicant explained that the pressure boundary reactor vessel sump area is presently inspected in accordance with the ASME Code IWE program. Inspections of component supports in this area are conducted, as are inspections for the reactor vessel lower head. The applicant further stated that enhancements are required to the Structural Monitoring Program to address the containment non-pressure boundary internal structure inspections. The Structural Monitoring Program will be enhanced to explicitly conduct and document a structural condition survey for this area. The applicant also explained the process used for controlling the temperature and monitoring degradation of structural components around the reactor vessel and the sump areas. The staff found the inspections and monitoring measures acceptable.

The staff found the process used, including the planned enhancements, for managing the degradation of structural components around the reactor vessel and the sump areas during the period of extended operation adequate and acceptable. The staff's concerns described in RAI 3.5-5 are resolved.

On the basis of its review, the staff found that the applicant had appropriately evaluated the AMR results involving reduction of strength and modulus of concrete structures due to elevated temperature for the containment, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

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 the steel containment shell or the steel liner plate for the containment.

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 containments.

The GALL Report, Chapter II, Containment Structures, Item A1.2-a states that for inaccessible areas (embedded containment steel shell or liner), loss of material is not significant if the following conditions are 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 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 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. If any of the above conditions cannot be satisfied, then a plant-specific aging management program for corrosion is recommended.

The applicant stated that plant operating experience has shown that borated water spills in containment have impacted the containment liner and accordingly, the liner plate has been selected to receive augmented inspections, category E-C, in accordance with ASME Code Section XI, Subsection IWE. In addition, the Boric Acid Corrosion Program is also credited with assessing and managing loss of material in the containment liner.

The staff reviewed the applicant's Boric Acid Corrosion Program and its evaluation is documented in SER Section 3.0.3.2.6.

The staff's review of LRA Section 3.5.2.2.1.4 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.

RAI 3.5-4. The Discussion column of LRA Item 3.5.1-12 refers to LRA Section 3.5.2.2.1.4 for further evaluation. In the discussion, the applicant noted that liner corrosion was identified in both units due to borated water leakage, and that ASME Code Subsection IWE augmented inspections would be performed in these areas. In RAI 3.5-4, dated July 27, 2004, the staff requested the applicant to provide a quantitative summary of extent of liner corrosion found in each unit, and the corrective actions taken. The applicant was also requested to include a discussion of acceptable liner plate corrosion before it is reinstated to its nominal thickness.

In its response, dated August 26, 2004, the applicant stated that the areas of concern include (1) the bottom containment liner plate (floor), which is covered by an eighteen-inch thick concrete floor, and (2) SW and CCW penetrations. The penetrations have detectable pitting in the flued head region. On occasion, spilled borated water has seeped into the liner plate floor crevice. The liner plate floor receives UT measurements at selected locations. The applicant further emphasized that the liner plate material loss has been minimal with no adverse effect to the pressure boundary function. In addition, the applicant stated that Sump A had coating degradation at the scum line but no notable material loss. Regarding the acceptable liner corrosion, the applicant stated that there is no absolute limit for material loss exceeding a percentage of nominal containment wall thickness that would necessitate a repair to restore nominal thickness. The acceptance criteria are based on the effect, or impact, corrosion would have on the containment structural integrity or leak tightness.

During a meeting, on February 15, 2005, the staff indicated and the applicant agreed, that this response required further clarification. The staff requested the applicant to clarify the corrective actions taken, when loss of material is identified in the containment penetration flued heads, containment liner, or sump liner. The staff noted that IWE-3500 does not provide specific guidance in this regard. The applicant was requested to provide a procedural description of the corrective actions taken when such a loss of material is identified.

In its response, a clarification letter dated March 15, 2005, the applicant summarized that the necessity for repair has been determined on a case-by-case basis. The table provided with the response showed the liner plate base thickness reduction was as high as 46 percent. The response indicated that such degradation was found acceptable without repair. Furthermore, the response noted that the 1/4-inch liner plate design is based on the predicted strains without leaking. As this process will be continued during the period of extended operation, the staff requested additional information regarding the basic criteria used in the engineering evaluation.

The staff considered this an unresolved item. The staff requested the applicant to provide a summary of the engineering evaluations performed for CAP 22754, and CAP 13912 (designated in the applicant's response table), including the type of corrosion (whether general, pitting, galvanic, etc.), loads considered in the evaluation, acceptable liner strains, and strain concentration factors considered, if applicable. The applicant was also requested to provide the procedure describing the "as left" condition of the degradation (*e.g.*, repairing, cleaning, recoating, and a schedule for reexamination to verify stability of the degradation). This was identified as open item (OI) 3.5-4.

In its response to OI 3.5-4, by letter dated June 10, 2005, the applicant provided the condition reports and the engineering evaluations (CR 01-1517 and CR 01-1220) prepared for the two events. The staff reviewed the applicant's response and its evaluation is documented below.

- CR-01-1517: The report refers to the NDE measurements of the basemat liner in 1988. Based on the 13 year period (1975 to 1988), the report calculates the rate of corrosion as .003 inches per year. The report concludes that it is very small rate; however, extending the same rate to 60 years will result in corrosion of liner plate at 0.18 inches, leaving the plate thickness of 0.10 inch at the end of the period of extended operation. This is not acceptable, in view of the fact that the basemat liner is inaccessible for IWE inspections, unless the applicant monitors the affected area(s) under augmented inspection (IWE-1241) and sets a limit on acceptable liner corrosion.

- CR-01-1220: For the liner plate attached to the concrete wall, the report statement "under normal operating condition, the liner experience no strain," is not correct. Though the liner is not accounted for in structural calculations, by virtue of its being anchored to the concrete, it experiences compressive strains due to dead load, prestressing and creep of concrete. This is evidenced by a number of prestressed and reinforced concrete containments having bulging of liners between the anchors. At the bottom of the containment wall, it is subjected to bending strains due to hoop prestressing and concrete creep. Unless an analysis is performed to show that, with the reduced thickness of 0.116 inch, the liner will be able to withstand the postulated loads without giving rise to a different mode of failure (*e.g.* pullout of the anchors, tearing of the plate because of strain concentration). Such corrosion without corrective action is not acceptable. The analysis must consider all the locked-in strains and superimposed strains due to pressure, temperature, and the postulated seismic loads. In the assessment, the staff noted that NRC has accepted up to 50 percent loss in liner thickness in a very localized areas without such analysis.

Subsequently, the staff indicated and the applicant agreed that details with respect to these engineering evaluations required further clarification. In its response dated July 8, 2005, the applicant stated that the steel liner for the concrete containment building receives an inservice inspection in accordance with IWE, 1992 Edition with 1992 Addenda. In accordance with Table IWE-2500-1, the acceptance standards for Examination Category E-A, Containment Surfaces, are discussed in IWE-3510 and IWE-3122. Conditions (degradation) that may affect containment structural integrity or leak tightness shall be accepted by engineering evaluation or corrected by repair or replacement. If thickness of the base metal is reduced by more than 10 percent of the nominal plate thickness, the component shall be acceptable by evaluation if the reduced thickness can be shown by analysis to satisfy the requirements of the design specifications. Furthermore, the applicant noted that if localized area thickness of the containment liner base metal is reduced by 50 percent or more of the nominal plate thickness, then, every attempt should be made to correct by repair or replacement. If the repair or replacement option is impractical, an acceptance by engineering evaluation option may be pursued. When component examination results require acceptance by engineering evaluation for flaws or areas of degradation (IWE-3122.4) and the component is found to be acceptable for continued service, the areas containing such flaws or degradation shall be re-examined during the next inspection period scheduled in accordance with Table IWE-2500-1, Examination Category E-C (IWE-2420(b)).

When the re-examinations reveal that the flaws or areas of degradation remain essentially unchanged for three consecutive inspection periods, then the areas containing such flaws or degradation no longer require augmented examination in accordance with Examination Category E-C (IWE-2420(c)). If localized area thickness of the base metal is reduced by approximately 50 percent or more of the nominal plate thickness, then the reexaminations required by IWE-2420(b) will be continued in the succeeding inspection periods and the provisions of IWE-2420(c) will not be applied. This evaluation, repair, or replacement discussion, and reexaminations will be included in the Acceptance Criteria element of the ASME Section XI, Subsections IWE and IWL Inservice Inspection Program of the LRA (Section B2.1.2). The above evaluation, repair or replacement, and re-examination requirements will assure that leak-tightness and structural integrity of the liner will be maintained.

After describing the general methodology for evaluating cracks and degradation of the liner plate, as discussed above, the applicant made the following commitments:

- An evaluation, repair or replacement requirement discussion will be included in the Acceptance Criteria element of the ASME Section XI, Subsections IWE and IWL Inservice Inspection Program of the LRA prior to the period of extended operation. If localized area thickness of the containment liner base metal is reduced by 50 percent or more of the nominal plate thickness, then every attempt should be made to correct by repair or replacement. If the repair or replacement option is impractical, an acceptance by engineering evaluation option may be pursued.
- If localized area thickness of the base metal is reduced by approximately 50 percent or more of the nominal plate thickness, then the re-examinations required by IWE 2420(b) will be continued in the succeeding inspection periods and the provisions of IWE-2420(c) will not be applied.

Based on the applicant's responses to RAI 3.5-4, the description of the process and the commitments discussed above, the staff found the overall approach in detecting and correcting the flaws and degradation in the containment liner plates acceptable. The staff's concerns are resolved; therefore, OI 3.5-4 is closed.

On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving loss of material due to corrosion in inaccessible areas of the steel containment shell or the steel liner plate for the containment, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>Loss of Prestress Due to Relaxation, Shrinkage, Creep, and Elevated Temperature</u>. In LRA Section 3.5.2.2.1.5, the applicant stated that loss of prestress 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 4.5 documents the staff's review of the applicant's evaluation of this TLAA.

<u>Cumulative Fatigue Damage</u>. In LRA Section 3.5.2.2.1.6, 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.

<u>Cracking Due to Cyclic Loading and Stress Corrosion Cracking (SCC)</u>. 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 cracking due to cyclic loading and SCC.

SRP-LR Section 3.5.2.2.1.7 states that cracking of containment penetrations due to cyclic loading or SCC could occur in containments. Further evaluation of inspection methods is recommended to detect cracking due to cyclic loading and SCC because visual (VT-3) examinations may be unable to detect this aging effect.

The applicant stated that a fatigue review was performed for the liner penetrations and that cracking due to cyclic loading is addressed as a TLAA in LRA Section 4.3.11. Additionally, the applicant stated that carbon steel components within penetrations are not susceptible to SCC and that stainless steel components require both a high temperature, greater than 140 °F, and exposure to an aggressive chemical environment (*e.g.*, exposure to chlorides). The bellows at PBNP are not exposed to aggressive chemical environments.

The staff reviewed the information provided in the LRA and agreed with the applicant that carbon steel components within penetrations are not susceptible to SCC, persuant to the GALL Report guidance. Also, cracking due to cyclic loading of the liner plate and penetrations is a TLAA which is evaluated and discussed in SER Section 4.6.

The staff's review of LRA Section 3.5.2.2.1.7 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.

<u>RAI 3.5-12</u>. In LRA Section 3.5.2.2.1.7, the applicant stated that SCC is not an applicable aging mechanism for penetrations, sleeves, bellows, and dissimilar metal welds. The applicant also stated that the liner penetrations have had a fatigue review and are bounded by the GALL Report line Item 3.5.1-01/II.A3.1-b. Therefore, the applicant did not address cracking due to cyclic loading. In RAI 3.5-12, dated March 30, 2005, the staff requested the applicant to address the difference between its position and the GALL Report recommendation of enhanced inspection methods. The staff noted that the TLAA in LRA Section 4.3.11 does not detect and manage cracking due to cyclic loading. The applicant was requested to provide further clarification for crediting this specific line Item to manage cracking due to cyclic loading.

During conversations with the staff, the applicant clarified that if explicit fatigue analyses were performed, then only a TLAA is required. The staff agreed with the applicant's approach. The applicant will provide a formal letter to reflect this statement. This was identified as confirmatory item (CI) 3.5-12.

In its response to CI 3.5-12, by letter dated June 9, 2005, the applicant clarified its basis for concluding that the use of a fatigue analysis as the basis for managing fatigue is consistent with the positions stated in the GALL Report (NUREG-1801 Vol. 1, Table 5, Items 3.5.1-1 and 3.5.1-2). In addition, the applicant stated that SCC is not an applicable aging effect, due to the lack of an aggressive chemical environment. Further, the applicant clarified that aging management of the containment penetration sleeves is addressed by the ASME Section XI, Subsection IWE and IWL Inservice Inspection Program and the Boric Acid Corrosion Program. Lastly, the applicant stated that PBNP does not have any penetration bellows in the scope of license renewal.

The staff found the applicant's response to RAI 3.5-12, the categorization of aging effects and its aging management appropriate and consistent with the guidance of the GALL Report. The staff's concern is resolved and, therefore, CI 3.5-12 is closed.

<u>RAI 3.5-1</u>. In discussing LRA Table 3.5.1 Item Number 3.5.1-3, the applicant stated that the AMR results are consistent with NUREG-1801. NUREG-1801, Item A3.1 recommends further evaluation regarding the stress corrosion cracking of containment bellows. In RAI 3.5-1, dated July 27, 2004, the staff requested the applicant to provide additional information regarding the

containment pressure boundary bellows, relevant operating experience, and method(s) used to detect their age-related degradation. The staff also noted that in many cases, IWE VT-3 examination and Appendix J, Type B testing cannot detect aging effects as discussed in NRC IN 92-20.

In its response, dated August 26, 2004, the applicant stated that PBNP does not have any containment penetration bellows that function as a pressure boundary within the scope of license renewal. The applicant referred to FSAR pages 5.1-65 and 5.1-66, and Figures 5.1-2 and 5.1-16 for a description of the configuration of the containment penetrations, and clarified that containment bellows are not provided as part of the containment pressure boundary design. All penetrations with bellows are external to containment and are not subject to containment pressure. The applicant noted that the fuel transfer tube penetration has bellows with a leak-tight barrier function for refueling water at the refueling cavity and no containment pressure boundary function. The staff's review of the figures cited by the applicant confirmed that the PBNP containments do not have any pressure boundary bellows. The staff's concerns described in RAI 3.5-1 are resolved.

On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving management of cracking due to cyclic loading and stress corrosion cracking for the containment, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

<u>RAI 3.5-2</u>. During its review, the staff inquired about the integrity of seals and gaskets of the containment mechanical and electrical penetrations. For seals and gaskets related to containment penetrations, in LRA Item Number 3.5.1-6, containment ISI and containment leak rate testing have been identified as the designated aging management programs. For equipment hatches and air-locks, the staff agreed with the applicant's assertion that the leak rate testing program will monitor aging degradation of seals and gaskets, as they are leak rate tested after each opening. In RAI 3.5-2, dated July 27, 2004, the staff requested the applicant to provide information regarding the adequacy of Type B leak rate testing frequency to monitor aging degradation of seals and gaskets of mechanical and electrical penetrations.

In its response, dated August 26, 2004, the applicant stated that PBNP is committed to Option B of 10 CFR 50, Appendix J. RG 1.163 stipulates a local leak rate test (LLRT) frequency of up to 60 months for Type C tested penetrations. The applicant affirmed that PBNP employs the same 60-month maximum frequency for all Type B tested penetrations. The penetrations of interest are the ones that utilize an elastomer seal and are Type B tested. The applicant also stated that the affected penetrations include the Conax and Westinghouse modular electrical penetration assembles (EPA), and noted that the majority of the EPAs are of the Westinghouse canister type with no elastomer material.

The staff found the response acceptable, as the applicant will monitor the integrity of the seals and gaskets associated with the containment mechanical and electrical penetrations every 60 months in accordance with the RG 1.163 criteria. The staff's concern described in RAI 3.5-2 is resolved.

On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results for the containment, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2 Class 1 Structures

The staff reviewed LRA Section 3.5.2.2.2 against the criteria in SRP-LR Section 3.5.2.2.2, which addresses several areas discussed below.

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.

In LRA Section 3.5.2.2.2.1, the applicant addressed 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 increase 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.

Also, technical details of the aging management issue are presented in SRP-LR Subsection 3.5.2.2.1.2 for structure/aging effect combinations Items (5) and (6) and SRP-LR Subsection 3.5.2.2.1.3 for Item (8), above.

In LRA Section 3.5.2.2.2 and Tables 3.5.1 and 3.5.2-1, 3.5.2-6, and 3.5.2-10, the applicant indicated that the Structures Monitoring Program will not be used to manage the aging effects due to loss of material for those steel structural elements potentially exposed to borated water leakage. These structural elements include:

- ASME equipment, and pipe supports and restraints
- containment liner plate
- containment penetrations
- crane support girders
- electrical enclosures
- equipment supports, pipe restraints
- framing columns and beams
- HVAC ducts and supports
- mechanical equipment
- non-ASME equipment supports
- panels and cabinets
- platforms and stairs
- raceway supports
- raceways
- roof truss
- structural framings
- structural fasteners of RCS component supports
- supports of miscellaneous steel structures

The applicant proposed to use the Boric Acid Corrosion Program to manage the aging effects caused by boric acid corrosion. According to the applicant, this program complies with its response to NRC GL 88-05 and requires periodic visual inspection of systems that contain borated water for evidence of leakage or accumulations of dried boric acid. This inspection will cover all structural elements listed above. As stated in LRA Section B2.1.6, this program is an existing program that is consistent, without exceptions, with GALL XI.M10, "Boric Acid Corrosion." On this basis, the staff concluded that the use of the Boric Acid Corrosion Program to manage the aging effects of above mentioned steel structural elements due to loss of material caused by boric acid wastage is acceptable.

In LRA Section 3.5.2.2.2 and Tables 3.5.1 and 3.5.2, the applicant indicated that the Structures Monitoring Program will not be used to cover concrete structural elements to be used as fire barriers, flood barriers, missile barriers, shelters and supports. These structural elements include walls, ceilings, floors, columns, roofs, equipment pedestals, and the spent fuel pool. For these concrete structural elements, the applicant stated that no aging effects requiring management were identified. However, the applicant proposed to use the Fire Protection Program for periodic monitoring of potential degradation. As stated in LRA Section B2.1.10, under this program, periodic visual inspections of structural elements will be performed to ensure that the function capability and operability of these barriers is maintained. From its review of the LRA, the staff found that the aging effects of concrete structural elements will be managed by the Structures Monitoring Program and that periodic inspection under the Fire Protection Program will be performed to ensure that the intended functions of these structural elements are maintained.

The staff's review of LRA Section 3.5.2.2.2 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.

RAI 3.5-11. In LRA Table 3.5.2-2, the applicant indicated that aging effects (changing material properties and loss of material of all wood/outdoor with the intended function of missile barrier) are to be managed by the Structures Monitoring Program. However, the staff's review of LRA Section B2.1.20 found that the scope of the Structures Monitoring Program does not include wood components. In RAI 3.5-11, dated July 7, 2004, the staff requested the applicant to clarify how the aging effects on wood structures will be managed.

In its response, dated August 26, 2004, the applicant stated that the Structures Monitoring Program, as detailed in LRA Appendix B, provides a detailed discussion of the 10 program elements. The element "Parameters Monitored or Inspected" does not explicitly make reference to wood material. The applicant clarified that the omission of reference to wood material was an oversight, as this item is presented in LRA Table 3.5.2-2 on page 3-446. The applicant committed to correct this omission during the annual LRA update. The staff determined that the applicant's commitment is acceptable and resolves the staff's concern described in RAI 3.5-11.

In LRA Section 3.5.2.2.2.1, the applicant stated that its Structures Monitoring Program identifies that an aging mechanism is present and active. The applicant stated that the Structures Monitoring Program also provides confirmation and verification of the absence of all types of aging effects. The applicant further stated that aging effects may be absent if the materials of construction, design specifications, and operational environment preclude an aging mechanism, but it is prudent to periodically assess the condition of SSCs regardless of the likelihood that a particular aging mechanism is applicable. The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. Additional discussion of specific structure/aging effect combinations is documented below.

(1) Freeze-thaw. SRP-LR Section 3.5.2.2.1.2 does not address freeze-thaw as an aging mechanism for concrete containments because no further evaluation is recommended in the GALL Report. However, ISG-03 clarifies the staff position that further evaluation is appropriate if the applicant's facility is subject to moderate to severe weathering conditions unless the concrete meets certain specifications and subsequent inspections have confirmed that the aging mechanism has not caused degradation of the concrete.

PBNP is located in a region considered to have severe weathering conditions. In the LRA, the applicant stated that the contract specified air contents are within the range specified by ACI 318-63, and the contract specified water-to-cement ratio meets the recommendations of ACI 318-63. Therefore, loss of material and cracking of concrete due to freeze-thaw are not probable aging effects and have not been observed to date.

The staff interviewed the applicant's technical staff and confirmed that the concrete at PBNP was allowed to properly cure. In addition, it was confirmed that a loss of material from freeze-thaw has not been observed, either through the applicant's ASME Code Section XI, Subsections IWE and IWL Inservice Inspection Program or the Structures Monitoring Program.

On the basis that concrete that satisfies the requirements of ACI 318-63 will meet the recommendations of the GALL Report as clarified by ISG-03, and on the basis of the lack of freeze-thaw effects to date, the staff found that loss of material and cracking due to freeze-thaw will be adequately managed.

(2a) Leaching of calcium hydroxide. SRP-LR Section 3.5.2.2.2.1 states that cracking, spalling, and increases in porosity and permeability due to leaching of calcium hydroxide could occur in inaccessible areas of PWR concrete and steel containments. The GALL Report, as updated by ISG-3, recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas exposed to flowing water, unless the criteria of ACI 201.2R are met.

The GALL Report states that leaching of calcium hydroxide becomes significant only if the concrete is exposed to flowing water. Even if reinforced concrete is exposed to flowing water, such leaching is not significant if the concrete is constructed to ensure that it is dense, well-cured, has low permeability, and that cracking is well controlled.

The applicant stated that the original specifications met the intent of ACI 201.2R, and that a change in material properties due to leaching of calcium hydroxide is not a probable aging effect and has not been observed to date. The applicant used concrete per ACI 318-63 to construct these components. The differences between the ACI 318 concrete and ACI 201 standard are concrete rated at 3500 psi, some concrete cured to a time that was slightly shorter, use of type 1 versus type 2 cement and tested its aggregate per alternate ASTM C 295 and C 227. The lower strength and shorter cure time were consistent with the plant design criteria and affect abrasion resistance primarily. Type 1 cement is a higher quality cement than type 2. The alternate aggregate ASTM test standards are accepted by the GALL Report as an alternative.

As documented in the audit and review report, the staff reviewed the information provided in the LRA and held discussions with the applicant. The staff considered these differences and concluded that the ACI concrete possesses comparable aging resistance properties and will perform as well as concrete fabricated to the later ACI 201-2R guidance. The staff found that, based on the concrete specifications for Class 1 structures, the applicant is consistent with the GALL Report as updated by ISG-03, and demonstrated that cracking, spalling, and increases in porosity and permeability due to leaching of calcium hydroxide will be adequately managed.

(2b) Aggressive chemical attack. SRP-LR Section 3.5.2.2.2.1 states that cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack could occur in inaccessible areas of Class 1 structures. The GALL Report recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL Report, as updated in ISG-3, cannot be satisfied.

The GALL Report, as updated by ISG-03, states that aggressive chemical attack is not significant unless pH is less than 5.5, chlorides are greater than 500 ppm, or sulfates are greater than 1500 ppm.

The applicant stated that concrete degradation in air due to aggressive rainwater is insignificant and the below-grade environment is not aggressive. The Structures Monitoring Program requires periodic monitoring of ground/lake water to confirm that the water chemistry remains nonaggressive. Concrete degradation due to aggressive chemical attack has not been observed to date at PBNP.

The staff's review of LRA Section 3.5.2.2.2.1 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.

RAI 3.5-10. In LRA Section 3.5.2.2.2.1, the applicant stated that the Structures Monitoring Program requires periodic monitoring of ground/lake water to verify that the chemistry remains non-aggressive. However, the staff's review of the Structures Monitoring Program (LRA Item B2.1.20) revealed that the applicant did not commit to a program to monitor the ground/lake water chemistry. Therefore, in RAI 3.5-10, dated July 27, 2004, the staff requested the applicant to clarify this inconsistency.

In its response, dated August 26, 2004, the applicant stated that PBNP has a groundwater monitoring program (reference NP 7.7.9, Attachment D and Form PBF-7043). Data have been collected for groundwater level and chemical analysis, including pH and chloride determination. The applicant further indicated that groundwater level measurements are performed at an initial frequency once every quarter. The applicant will initially perform groundwater chemistry (pH, chlorides, and sulfates) monitoring at a frequency of once every nine months. At such frequency, monitoring will facilitate obtaining data affected by the seasonal rotation. A number of data points would be obtained with the above frequency. Based on an analysis and trend of the data, a determination will be made as to the appropriate frequency for continued monitoring. Subsequently, in response to CI 3.5-13, by letter dated June 9, 2005, the applicant committed to monitor ground water chemistry at least once every 5 years. The staff's review found that the applicant does have a groundwater monitoring program to be used to monitor the quality of groundwater by collecting data, analyzing water chemistry and content, and ensuring that the quality of groundwater meets the GALL criteria. On this basis, the staff's concern described in RAI 3.5-10 is resolved.

The staff found that, based on the nonaggressive below-grade/lake-water environment, the applicant is consistent with the GALL Report, as updated by ISG-03, and has demonstrated that cracking, spalling, and increases in porosity and permeability due to aggressive chemical attack will be adequately managed.

(3) Reaction with aggregates. SRP-LR Section 3.5.2.2.2.1 does not address reaction with aggregates as an aging mechanism for concrete containments because no further evaluation is recommended in the GALL Report. However, ISG-03 clarifies the staff position that further evaluation is appropriate if investigations, tests, or examinations have demonstrated that the aggregates are reactive.

The applicant stated that during construction, the aggregates were tested for potential reactivity in accordance with ASTM C227 and ASTM C295. Consequently, cracking and expansion due to reaction with aggregates are not probable aging effects and have not been observed to date.

ISG-03 states that aggregates are not reactive if constructed with concrete using the ASTM standards. The staff found that the applicant tested the aggregates using the ASTM standards, as recommended by the GALL Report, as updated by ISG-03, and demonstrated that cracking due to reaction with aggregates will be adequately managed.

(4) Corrosion of embedded steel. SRP-LR Section 3.5.2.2.2.1 states that loss of material due to corrosion of embedded steel could occur in inaccessible areas of Class 1

structures. The GALL Report, as updated by ISG-03, recommends further evaluation of plant-specific programs to manage the aging effects for inaccessible areas if specific criteria defined in the GALL Report cannot be satisfied.

The GALL Report states that a plant-specific program is required only if the below-grade environment is aggressive.

The applicant stated that, since the embedded steel is not exposed to an environment that is considered aggressive, loss of material, cracking, and loss of bond due to corrosion of embedded steel are not probable aging effects and have not been observed to date.

The staff's review of LRA Section 3.5.2.2.2.1 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.

RAI 3.5-6. LRA Section 3.5.2.2.2.1, "Aging of Structures Not Covered by Structures Monitoring Program," states that since the embedded steel is not exposed to an environment that is considered aggressive, loss of material, cracking, and loss of bond due to corrosion of embedded steel are not probable aging effects and have not been observed to date. The staff's concern is that, based on its past experience, many cases of corroded embedded steel (rebars and/or anchors) have been identified even within reinforced concrete elements exposed to a non-aggressive environment. In RAI 3.5-6, dated July 27, 2004, the staff requested the applicant to provide a basis for its statement.

In its response, dated August 26, 2004, the applicant referred to GALL Item III.A1.1-e, which states that if the environment is not aggressive, the aging effects such as loss of material, cracking, and loss of bond are not significant. In addition, in its response to RAI 3.5-10, the applicant committed to initially monitor water chemistry every nine months to ensure that the contents (pH, chlorides, and sulfate) of groundwater are within the GALL limits. Based on an analysis and trend of the data, a determination will be made as to the appropriate frequency for continued monitoring. The staff considers the applicant's response acceptable because the applicant's commitment ensures aging management. The staff's concern described in RAI 3.5-6 is resolved.

The staff found that, based on the nonaggressive below-grade/lake-water environment, the applicant is consistent with the GALL Report, as updated by ISG-03, and demonstrated that cracking, spalling, loss of bond, and loss of material due to corrosion of embedded steel will be adequately managed.

(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 1 structures. Some plants may rely on a dewatering system to lower the site groundwater level. If the plant's CLB credits a dewatering system, the GALL Report recommends verification of the continued functionality of the dewatering system during the period of extended operation. The GALL Report recommends no further evaluation if this activity is included within the scope of the applicant's Structures Monitoring Program.

In LRA Section 3.5.2.2.2.1, the applicant stated that all structures are founded on either spread footings, basemats, or basemats with steel foundation piles that are driven to refusal. Settlement monitoring and structural inspection indicate no visible evidence of uneven or excessive settlement since construction of the station. Cracking, distortion, and an increase in component stress levels due to settlement are not probable aging effects and have not been observed to date. Additionally, according to LRA Table 3.5.0-1, Item 13, there is no permanent dewatering system at PBNP.

The staff's review of LRA Section 3.5.2.2.2.1 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.

RAI 3.5-7. Based on observed experience, as long as structural foundations are founded on soils, even with spread footings, basemats, or basemats with steel piles driven to the refusal, etc., it is expected that settlements will occur, especially for sandy soil. These settlements, in most cases, cannot be detected by visual inspection. In RAI 3.5-7, dated July 27, 2004, the staff requested the applicant to clarify its statement that settlement monitoring and structural inspections did not indicate visible evidence of uneven or excessive settlement since construction of the station. The applicant was requested to substantiate its statement based on measurements taken instead of visual observations or judgment.

In its response, dated August 26, 2004, the applicant stated that consolidation of soils beneath building foundations typically occurs within the first three to four years after construction. Consolidation of the soil after that time frame is typically negligible. PBNP has a facilities settlement monitoring program (reference NP 7.7.9, Attachment E and Bechtel drawing 6118-C-102). During original plant construction, numerous benchmarks were established throughout the plant. The benchmarks were first surveyed in the fall of 1969. Subsequent surveys have been performed and differential settlement values determined. To date, the average differential settlement from all benchmarks is 0.636 inches. The maximum differential settlement between any of the points (non-adjacent) is 1.296 inches. The applicant confirmed that settlement monitoring will continue during the period of extended operation.

The staff's review of the applicant's response found that the settlement of plant building structures was monitored by survey (instead of visual inspection) under the settlement monitoring program. The average differential settlement from all benchmarks is less than one inch and the maximum differential settlement between any of the points (non-adjacent) is 1.296 inches, which is negligible. The applicant also committed in the response to continue settlement monitoring during the period of extended operation. On the basis of its evaluation and the above discussion the staff's concern described in RAI 3.5-7 is resolved.

The staff found that, based on the foundation designs used at PBNP, the applicant satisfied the specific criteria in the GALL Report and demonstrated that cracking, distortion, and increase in component stress level due to settlement will be adequately managed.

(6) Erosion of porous concrete subfoundation. SRP-LR Section 3.5.2.2.2.1 refers to SRP-LR Section 3.5.2.2.1.2 for discussion of erosion of porous concrete subfoundation. SRP-LR Section 3.5.2.2.1.2 states that reduction of foundation strength due to erosion of porous concrete subfoundations could occur in all types of Class 1 structures. Some plants may rely on a dewatering system to lower the site groundwater level. If the plant's CLB credits a dewatering system, the GALL Report recommends verification of the continued functionality of the dewatering 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.

SRP-LR Section 3.5.2.2.1.2 states that reduction of foundation strength due to erosion of porous concrete subfoundations could occur in all types of PWR containments. LRA Section 3.5.2.2.1.2 states that the structure foundations were constructed of normal concrete and not the porous type, and that the foundations are not subject to flowing water. The Structures Monitoring Program monitors for settlement and cracking.

The staff found that, based on the foundation designs used at PBNP and based on the absence of porous concrete in subfoundations, the applicant has satisfied the specific criteria in the GALL Report and demonstrated that cracking, distortion, and increase in component stress level due to settlement and reduction of foundation strength due to erosion of porous concrete subfoundations will be adequately managed.

(7) Corrosion of structural steel components. SRP-LR Section 3.5.2.2.2.1 states that corrosion of structural steel components could occur and that further evaluation is necessary only for structure/aging effect combinations not covered by the Structures Monitoring Program.

The staff reviewed the AMR results involving management of aging effects resulting from corrosion of structural steel components and confirmed that the Structures Monitoring Program addresses each of the affected SSCs. The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving this aging effect and that corrosion of structural steel components is adequately managed by the Structures Monitoring Program.

(8) Elevated temperatures. SRP-LR Section 3.5.2.2.2.1 refers to SRP-LR Section 3.5.2.2.1.3 for discussion of elevated temperatures. SRP-LR Section 3.5.2.2.1.3 states that reduction of strength and modulus of elasticity due to elevated temperatures could occur in Class 1 structures. The GALL Report calls for a plant-specific aging management program 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)).

The applicant stated that for plant areas of concern, temperatures are normally maintained below the specified limits; therefore, loss of material, cracking, change in material properties due to elevated temperatures are not probable aging effects and have not been observed to date. However, in response to RAI 3.5-3, the applicant stated that the concrete temperatures in Unit 2 around the main steam lines were found to be about 380 °F for an unknown period of time. Such sustained temperatures not only affect the concrete compressive strength and its elastic modulus, but they also accentuate the concrete creep and relaxation of prestressing tendons located in the vicinity of high temperature areas. The net effect could be lower tendon forces in these areas. In its response, dated August 26, 2004, the applicant stated that in 2003 corrective actions were initiated to address this issue. The applicant further stated that the penetrations will be restored to their original design condition during the Unit 2 Spring 2005 refueling outage. This inspection will confirm whether or not there are any adverse conditions. If adverse conditions are identified, corrective actions will be taken.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. The staff also reviewed the AMR results and RAI response involving management of aging effects resulting from elevated temperature. The staff found that the applicant had appropriately evaluated AMR results involving reduction of strength and modulus due to elevated temperature, as recommended in the GALL Report, and that it is adequately managed by the Structures Monitoring Program.

(9) Aging effects for stainless steel liners for tanks. The applicant stated that no tanks with stainless steel liners are included in the structural AMRs. Tanks subject to an AMR are evaluated with their respective mechanical systems.

On the basis of its review, the staff agreed that no tanks with stainless steel liners are included in the structural AMRs.

The staff reviewed the results of the applicant's AMR for accessible interior and exterior concrete and steel components of Class 1 structures. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving management of aging of accessible interior and exterior concrete and steel components of Class 1 structures. Since the applicant's AMR results are otherwise consistent with 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Aging Management of Inaccessible Areas. The staff reviewed the 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.

The applicant stated that the below-grade environment is not aggressive. The applicant uses the Structures Monitoring Program to examine below-grade concrete when it is exposed by excavation and monitor the ground/lake water to confirm that the chemistry remains nonaggressive. Inspections of accessible concrete have not revealed degradation from aggressive chemical attack or corrosion of embedded steel.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. The staff agreed with the applicant that the below-grade environment is not aggressive and that excavated concrete has been and will continue to be monitored. The staff found that increases in porosity and permeability, loss of material, cracking due to aggressive chemical attack and cracking, loss of bond, and loss of material due to corrosion of embedded steel are adequately managed for concrete in inaccessible areas.

The staff's review of LRA Section 3.5.2.2.2.2 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.

<u>RAI 3.5-8</u>. LRA Section 3.5.2.2.2.2, states that since the below-grade/lake water environment is nonaggressive and the structures monitoring program requires periodic monitoring of ground/lake water to verify that the water chemistry remains non-aggressive, the loss of material and change in material properties due to aggressive chemical attack are not probable aging effects at PBNP. Also, since the embedded steel is not exposed to an environment that is considered aggressive, loss of material, cracking, and loss of bond due to corrosion of embedded steel are not probable aging effects. The staff agreed with this statement only for the case of uncracked reinforced concrete elements. However, the staff identified a concern that the inaccessible concrete components, such as exterior walls below grade and embedded structural foundations, may crack due to settlement and corrosion of reinforcing steel may be expected. In RAI 3.5-8, dated July 27, 2004, the staff requested the applicant to justify the validity of the LRA statement.

In its response, dated August 26, 2004, the applicant referred to Section III of the GALL Report, which states that, if the environment is not aggressive, the aging effects such as loss of material, cracking, and loss of bond are not significant. In addition, inspection of all PBNP concrete structures and buildings within the scope of license renewal will look for signs of concrete distress cracking, rust staining, and spalling from any aging effect/source type to identify any aging effect. The staff determined that the applicant's response is consistent with the GALL Report. The staff's concern described in RAI 3.5-8 is resolved.

<u>RAI 3.5-9</u>. LRA Table 3.5.1 Item 3.5.1-21 states that the aging management program will be plant-specific, and the Discussion column of the table refers to LRA Section 3.5.2.2.2.2. However, there is no plant-specific aging management program described in this LRA section. In RAI 3.5-9, dated July 27, 2004, the staff requested the applicant to clarify this statement.

In its response, dated August 26, 2004, the applicant stated that Line Item Table 3.5.1-21, Discussion column, dealing with inaccessible concrete areas, points to Section 3.5.2.2.2.2 for further evaluation. LRA Section 3.5.2.2.2.2 concludes that there are no aging effects for this line item. LRA Table 3.5.1-21 makes reference to a plant-specific program if an aggressive below-grade environment exists, which it does not. Therefore, no plant-specific program is needed or identified. As discussed in the resolution of RAI 3.5-6, the staff found the applicant's clarification consistent with the GALL Report. The staff's concern described in RAI 3.5-9 is, therefore, resolved.

On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving management of aging of accessible interior and exterior concrete and steel components of Class 1 structures. Since the applicant's AMR results are otherwise consistent with 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.3 Component Supports

The staff reviewed LRA Section 3.5.2.2.3 against the criteria in SRP-LR Section 3.5.2.2.3, which addresses several areas discussed below.

Aging of Supports Not Covered by the 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 and Table 3.5.1, line item 3.5.1-29, 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.

In LRA Table 3.5.1, line item 3.5.1-29, the applicant stated that for Groups B1-B5 these component supports are included in the Structures Monitoring Program. In LRA Table 3.5.2-10, the applicant stated that loss of material due to corrosion of steel support components is an aging effect requiring management. The applicant stated that this aging effect is managed by the Structures Monitoring Program.

LRA Table 3.5.1, line item 3.5.1-32, states that component supports in Group B1 are managed using the ASME Code Section XI, Subsection IWF Inservice Inspection Program. The applicant further stated that its Structures Monitoring Program includes baseplates, grout, and expansion anchors for Group B1 supports, and are inspected at the same time as the ASME Code Section XI IWF Inservice Inspections.

Component supports have been evaluated for the following aging mechanisms:

(1) Reduction in concrete anchor capacity due to surrounding concrete for Groups B1-B5 supports.

    The applicant stated that its concrete anchors and surrounding concrete are included in the Structures Monitoring Program.

(2) Reduction/loss of isolation function due to degradation of vibration isolation elements for Group B4 supports.

The applicant stated that Structures Monitoring Program identifies and evaluates the degradation of vibration isolation elements.

The staff reviewed the applicant's Structures Monitoring Program and ASME Code Section XI, Subsection IWF Inservice Inspection Program, and its evaluations are documented in SER Sections 3.0.3.2.19 and 3.0.3.3.2, respectively.

The staff's review of LRA Section 3.5.2.2.3.1 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.

RAI 3.5-14. In LRA Table 3.5.1, Item 3.5.1-33, the applicant stated that the Bolting Integrity Program includes the use of Inservice Inspection to evaluate and monitor crack initiation and growth due to SCC, if present, in high strength low-alloy steel bolts used in NSSS component supports. In LRA Tables 3.5.2-1 through 3.5.2-14, the applicant does not address Group B1.1, high-strength, low-alloy bolts.

In LRA Section B2.1.4, the applicant indicated that high-strength component support bolting is used in pinned connections associated with steam generator, reactor coolant pumps and reactor vessel supports and is loaded only in shear with no preload stress.

In RAI 3.5-14, dated March 31, 2005, the staff requested the applicant to identify the aging management program for the Group B1.1 high-strength, low-alloy bolts. During conversations with the staff, the applicant stated that this RAI is similar to one previously issued for the Bolting Integrity Program, RAI B2.1.4-3. The staff reviewed the applicant's response and found it acceptable. The staff's evaluation of this RAI is documented in SER Section 3.0.3.2.4. The applicant also acknowledged that PBNP has some torqued high-strength bolts. The applicant will supplement its response to reflect this statement. This was identified as confirmatory item (CI) 3.5-14.

In its response to CI 3.5-14, by letter dated April 29, 2005, the applicant stated that the aging effect mechanism associated with line item 3.5.1-33 is "crack initiation and growth due to SCC" and that it had evaluated SCC as not being an applicable aging effect requiring management at PBNP. The aging effects requiring management for Group B1.1 bolting include line item 3.5.1-31, loss of material due to boric acid wastage; and line item 3.5.1-32, loss of material due to general corrosion. These aging effects are depicted in LRA Table 3.5.2-10, which addresses Group B1.1 bolting. The intent of the Discussion column for line item 3.5.1-33 was that "if present," cracking may be detected during ISI inspections, which would evaluate any noted non-conformance.

The staff evaluated the applicant's response to RAI 3.5-14 and the technical basis provided and agreed that SCC is not an active aging mechanism requiring management in this situation. The staff's concern is resolved and, therefore, CI 3.5-14 is closed.

On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving management of aging of supports not covered by Structures Monitoring

Program for the component supports, as recommended in the GALL Report. Since the applicant's AMR results are otherwise consistent with 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

Cumulative Fatigue Damage Due to Cyclic Loading. In LRA Section 3.5.2.2.3.2, 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.

3.5.2.2.4 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).

3.5.2.3 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 3.5.2-14, the staff reviewed additional details of the results of the AMRs for material, environment, aging effect requiring management, and AMP combinations that are not consistent with the GALL Report or are not addressed in the GALL Report.

As documented under RAI 2.1-1 in SER Section 2.1, by letter dated April 29, 2005, the applicant changed the methodology used to determine the nonsafety-related SCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). As a result of the implementation of the scoping methodology changes, the applicant identified no changes to LRA Tables 3.5.2-1 through 3.5.2-14.

In LRA Tables 3.5.2-1 through 3.5.2-14, 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 requiring management 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 demonstrated that the effects of aging will be adequately managed so that the intended function will be maintained during the period of extended operation.

3.5.2.3.1 Containments, Structures, and Component Supports Components That Have No Aging Effects - Tables 3.5.2-1 through 3.5.2-14

In LRA Tables 3.5.2-1 through 3.5.2-14, the applicant identified line items where no aging effects were identified as a result of the aging review process. Specifically, instances in which the applicant stated that no aging effects were identified occurred when components fabricated from structural stainless steel, carbon steel foundation piles, glass, grout, concrete (reinforced) or fiber-reinforced cement that were exposed to air, or were buried concrete (reinforced). Neither air nor buried concrete is identified in the GALL Report as an environment for these components and materials. No aging effects are considered to be applicable to buried reinforced concrete or structural stainless steel, carbon steel foundation piles, glass, grout, concrete (reinforced) or fiber reinforced cement that have been exposed to air environments.

On the basis of its review of current industry research and operating experience, the staff found that dry air on metal will not result in aging that will be of concern during the period of extended operation. There is not an aging effect/mechanism on structural stainless steel, carbon steel foundation piles, glass, grout, concrete (reinforced) or fiber-reinforced cement in air environment. Therefore, the staff concluded there are no applicable aging effects requiring management for structural stainless steel, carbon steel foundation piles, glass, grout, concrete (reinforced) or fiber reinforced cement in air environment. The staff also found that no applicable aging effects for buried reinforced concrete or structural stainless steel, carbon steel foundation piles, glass, grout, concrete (reinforced) or fiber reinforced cement that were exposed to air environments.

3.5.2.3.2 Containment Unit 1 and 2 Building Structure - Aging Management Evaluation - Table 3.5.2-1

The staff reviewed LRA Table 3.5.2-1, which summarized the results of AMR evaluations for the Units 1 and 2 containment building structure component groups.

The applicant proposed to manage loss of material due to boric acid wastage of structural steel carbon material for component types of structural carbon steel/indoor including the containment liner, keyway channels, exposed portions of embedded steel, electrical and mechanical penetrations and bolting exposed to indoor with no external air conditioning environment, by using the Boric Acid Corrosion Program.

The staff reviewed the applicant's Boric Acid Corrosion Program and its evaluation is documented in SER Section 3.0.3.2.6. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to boric acid wastage for components in the Units 1 and 2 containment structure is effectively managed using the Boric Acid Corrosion Program. Therefore, the staff found that management of loss of material due to boric acid wastage in the Units 1 and 2 containment building structure using this program is acceptable.

The applicant proposed to manage loss of material due to wear of structural copper alloy material (Zn<15%) for component type of structural copper alloy/indoor including airlock bushings exposed to indoor with no external air conditioning environment, by using the ASME Section XI, Subsection IWE and IWL Inservice Inspection Program.

The staff reviewed the applicant's ASME Section XI, Subsection IWE and IWL Inservice Inspection Program and its evaluation is documented in SER Section 3.0.3.2.2. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to wear for components in the Units 1 and 2 containment building structure is effectively managed using the ASME Section XI, Subsection IWE and IWL Inservice Inspection Program. Therefore, the staff found that management of loss of material due to wear in the Units 1 and 2 containment building structure using this program is acceptable.

The applicant also proposed to manage loss of material due to crevice corrosion, MIC, and pitting corrosion of structural stainless steel, including the refueling cavity liner, sandbox covers and fuel transfer tube including bolting exposed to treated water borated with temperature less than 140 °F, by using the Water Chemistry Control Program and ASME Section XI, Subsections IWE and IWL Inservice Inspection Program.

The staff reviewed the applicant's Water Chemistry Control Program and ASME Section XI, Subsections IWE and IWL Inservice Inspection Program. Its evaluations are documented in SER Sections 3.0.3.2.20 and 3.0.3.2.1. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to crevice corrosion, MIC, and pitting corrosion for components in the Units 1 and 2 containment building structure is effectively managed using the Water Chemistry Control Program and ASME Section XI, Subsections IWE and IWL Inservice Inspection Program. Therefore, the staff found that management of loss of material due to crevice corrosion, MIC, and pitting corrosion in the Units 1 and 2 containment building structure using these programs is acceptable.

3.5.2.3.3 Control Building Structure - Aging Management Evaluation - Table 3.5.2-2

The staff reviewed LRA Table 3.5.2-2, which summarized the results of AMR evaluations for the control building structure component groups.

The applicant proposed to manage loss of material due to general corrosion and due to wear of structural steel carbon material for the component type doors/indoor, including all doors throughout the building exposed to an indoor with no external air conditioning environment, by using the Structures Monitoring Program and the Fire Protection Program. The staff reviewed the applicant's Structures Monitoring Program and Fire Protection Program and its evaluations are documented in SER Sections 3.0.3.2.19 and 3.0.3.2.10, respectively.

On the basis of its review of the applicant's programs, and plant-specific and industry operating experience, the staff found that loss of material due to general corrosion and loss of material due to wear for components in the control building structure are effectively managed using the Structures Monitoring Program and Fire Protection Program. Therefore, the staff found that management of loss of material due to general corrosion and due to wear in the control building structure using these programs is acceptable.

The applicant proposed to manage change in material properties due to elevated temperature, cracking due to elevated temperature, ultraviolet radiation and ozone of elastomer materials for component type of elastomers/indoor, including rubber flap-DGR louver, rubber sill, sweep flood doors, gaskets, seals and the control room door exposed to indoor with no external air conditioning environment, by using the Fire Protection Program.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.10. The staff found that elastomers experience changes in material properties and cracking gradually. On the basis of its review of the applicant's programs, and plant-specific and industry operating experience, the staff found that change in material properties due to elevated temperature, cracking due to elevated temperature, ultraviolet radiation and ozone for components in the control building structure are effectively managed using the Fire Protection Program. Therefore, the staff found that management of change in material properties due to elevated temperature, cracking due to elevated temperature, ultraviolet radiation and ozone in the control building structure using this program is acceptable.

The applicant proposed to manage change in material properties and loss of material due to rot and mildew of wood for component type of wood/outdoor, including missile shield (an integral part of the diesel generator air intake) exposed to the outdoors, by using the Structures Monitoring Program.

In LRA Section 3.5.2.1.2, the applicant identified that the outdoor wood missile shield for the diesel generator air intake is subject to the aging effects of change in material properties and loss of material due to rot and mildew. For the management of these aging effects, the applicant proposed to use the Structures Monitoring Program, under which periodic inspections will be performed to ensure that these aging effects are properly managed. As discussed in the resolution of RAI 3.5-11, the applicant committed to revise the scope of the Structures Monitoring Program to include structural components made of wood material during the annual LRA update. Based on the applicant's commitment, the staff found that the identified aging effects of these structural elements will be properly managed.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. On the basis of its review of the applicant's programs, and plant-specific and industry operating experience, the staff found that changes in material properties and loss of material due to rot and mildew for components in the control building structure are effectively managed using the Structures Monitoring Program. Therefore, the staff found that management of changes in material properties due to rot and mildew and loss of material due to rot and mildew in the control building structure using this program is acceptable.

3.5.2.3.4 Circulating Water Pumphouse Structure - Aging Management Evaluation - Table 3.5.2-3

The staff reviewed LRA Table 3.5.2-3, which summarized the results of AMR evaluations for the circulating water pumphouse structure component groups.

The applicant proposed to manage loss of material due to abrasion and cavitation of reinforced concrete material for component type of concrete/raw water, including the forebay structure and the pump bays exposed to a submerged raw water environment, by using the Structures Monitoring Program.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. The staff found that limited loss of material due to abrasion and cavitation can occur in a raw water submerged external environment. On the basis of its review of the applicant's programs, plant-specific and industry operating experience, the staff found that loss of material due to abrasion and cavitation for components in the circulating water pumphouse structure is effectively managed using the Structures Monitoring Program. Therefore, the staff found that management of loss of material due to abrasion and cavitation in the circulating water pumphouse structure using this program is acceptable.

The applicant proposed to manage loss of material due to general corrosion and loss of material due to wear of structural steel carbon material for component type of indoor doors, including all doors throughout the building exposed to indoor with no external air conditioning environment, by using the Fire Protection Program.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.10. On the basis of its review of the applicant's programs, plant-specific and industry operating experience, the staff found that loss of material due to general corrosion and loss of material due to wear for components in the circulating water pumphouse structure are effectively managed using the Fire Protection Program. Therefore, the staff found that management of loss of material due to general corrosion in the circulating water pumphouse structure using this program is acceptable.

The applicant proposed to manage loss of material due to general corrosion of structural steel carbon material for component type of structural indoor carbon steel, including framings, columns, beams, structural carbon steel fasteners indoors, and structural steel framing exposed to indoor with no external air conditioning environment, by using the Structures Monitoring Program.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. On the basis of its review of the applicant's programs, plant-specific and industry operating experience, the staff found that loss of material due to general corrosion for components in the circulating water pumphouse structure is effectively managed using the Structures Monitoring Program. Therefore, the staff found that management of loss of material due to general corrosion in the circulating water pumphouse structure using this program is acceptable.

3.5.2.3.5 Diesel Generator Building Structure - Aging Management Evaluation - Table 3.5.2-4

The staff reviewed LRA Table 3.5.2-4, which summarized the results of AMR evaluations for the diesel generator building structure component groups.

The applicant proposed to manage loss of material due to general corrosion and due to wear of structural steel carbon material for component type of outdoor doors and indoor doors, including all doors throughout the building exposed to outdoor and indoor with no external air conditioning environment, by using the Fire Protection Program.

The applicant proposed to manage loss of material due to general corrosion of structural steel carbon material for component type of structural carbon steel fasteners indoor and outdoor, including all platform stairs and missile shields, and structural carbon steel indoor and outdoor, including all framing and missile shields, by using the Structures Monitoring Program.

The staff reviewed the applicant's Fire Protection Program and Structures Monitoring Program and its evaluations are documented in SER Sections 3.0.3.2.10 and 3.0.3.2.19. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to general corrosion and due to wear for components in the diesel generator building structure is effectively managed using the Fire Protection Program and Structures Monitoring Program. Therefore, the staff found that management of loss of material due to general corrosion and due to wear in the diesel generator building structure using these programs is acceptable.

3.5.2.3.6 Facade Units 1 and 2 Structure - Aging Management Evaluation - Table 3.5.2-5

The staff reviewed LRA Table 3.5.2-5, which summarized the results of AMR evaluations for the Units 1 and 2 facade structure component groups.

In LRA Table 3.5.2-5, the applicant stated that the AMRs for the Units 1 and 2 facade structure components are consistent with the GALL Report.

The staff confirmed that the AMR results are consistent with the GALL Report.

3.5.2.3.7 Primary Auxiliary Building Structure - Aging Management Evaluation - Table 3.5.2-6

The staff reviewed LRA Table 3.5.2-6, which summarized the results of AMR evaluations for the primary auxiliary building structure component groups.

The applicant proposed to manage loss of material due to general corrosion and due to wear of structural steel carbon material for component type of indoor doors, including all doors throughout the building exposed to indoor with no external air conditioning environment, by using the Structures Monitoring Program and the Fire Protection Program. The staff reviewed the applicant's Structures Monitoring Program and Fire Protection Program and its evaluations are documented in SER Sections 3.0.3.2.19 and 3.0.3.2.10, respectively.

On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to general corrosion and loss of material due to wear for components in the primary auxiliary building structure are effectively managed using the Structures Monitoring Program and the Fire Protection Program. Therefore, the staff found that management of loss of material due to general corrosion and loss of material due to wear in the primary auxiliary building structure using these programs is acceptable.

The applicant proposed to manage change in material properties due to elevated temperature, cracking due to elevated temperature, and due to ultraviolet radiation and ozone of elastomer materials for component type of indoor elastomers, including rubber sill, sweep and flood doors exposed to indoor with no external air conditioning environment, by using the Fire Protection Program and Structures Monitoring Program.

The staff reviewed the applicant's Fire Protection Program and Structures Monitoring Program and its evaluations are documented in SER Sections 3.0.3.2.10 and 3.0.3.2.19. The staff found that elastomers experience changes in material properties and cracking gradually. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that change in material properties due to elevated temperature, cracking due to elevated temperature, and cracking due to ultraviolet radiation and ozone for components in the primary auxiliary building structure is effectively managed using the Fire Protection Program and

Structures Monitoring Program. Therefore, the staff found that management of change in material properties due to elevated temperature, cracking due to elevated temperature, and cracking due to ultraviolet radiation and ozone in the primary auxiliary building structure using these programs is acceptable.

The applicant proposed to manage loss of material due to boric acid wastage of structural steel carbon material for component types of structural carbon steel indoor fasteners, including structural steel framing, indoor structural carbon steel, crane support girders, framing, columns, beams, roof trusses, platforms, and stairs in an indoor with no external air conditioning environment, by using the Boric Acid Corrosion Program.

The staff reviewed the applicant's Boric Acid Corrosion Program and found it acceptable. The staff's evaluation of this program is documented in SER Section 3.0.3.2.6. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to boric acid wastage for components in the primary auxiliary building structure is effectively managed using the Boric Acid Corrosion Program. Therefore, the staff found that management of loss of material due to boric acid wastage in the primary auxiliary building structure is acceptable.

The applicant proposed to manage loss of material due to crevice corrosion, MIC, and pitting corrosion of structural stainless steel exposed to borated water, including spent fuel pool (SFP), SFP canal, SFP gates; structural stainless steel, and storage racks exposed to treated and borated water with an external temperature less than 140 °F, by using the Water Chemistry Control Program.

The staff reviewed the applicant's Water Chemistry Control Program and its evaluation is documented in SER Section 3.0.3.2.20. The staff found that use of only the Water Chemistry Control Program for loss of materials in treated borated water is consistent with the GALL Report Table 2, Items III.A5.2-b and VII.A2.1-c. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to crevice corrosion, MIC, and pitting corrosion for components in the primary auxiliary building structure is effectively managed using the Water Chemistry Control Program. Therefore, the staff found that management of loss of material due to crevice corrosion, MIC, and pitting corrosion in the primary auxiliary building structure using this program is acceptable.

3.5.2.3.8 Turbine Building Units 1 and 2 Structure - Aging Management Evaluation - Table 3.5.2-7

The staff reviewed LRA Table 3.5.2-7, which summarized the results of AMR evaluations for the Units 1 and 2 turbine building structure component groups.

In LRA Table 3.5.2-7, the applicant stated that the AMRs for the Units 1 and 2 turbine building structure components are either consistent with the GALL Report or do not have an aging effect that requires management.

The staff confirmed that the AMR results are consistent with the GALL Report.

3.5.2.3.9 Yard Structures - Aging Management Evaluation - Table 3.5.2-8

The staff reviewed LRA Table 3.5.2-8, which summarized the results of AMR evaluations for the yard structures component groups.

The applicant proposed to manage loss of material due to surface runoff and erosion of earth material for component type of outdoor earth berm, including berm around the fuel oil storage tanks exposed to outdoor environment, by using the Structures Monitoring Program.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to surface runoff and erosion for components in the yard structures is effectively managed using the Structures Monitoring Program. Therefore, the staff found that management of loss of material due to surface runoff and erosion of earth material in the yard structures using this program is acceptable.

The applicant proposed to manage loss of material due to general corrosion and loss of material due to selective leaching of structural cast iron material for component type of outdoor structural cast iron, including manhole frames and covers exposed to outdoor environment, by using the Structures Monitoring Program.

In LRA Table 3.5.2-8, the applicant identified that outdoor carbon steel manhole covers, frames, bus ducts, cast iron manhole covers and frames are subject to the aging effect of loss of material due to general corrosion. Also, the cast iron manhole covers and frames are subject to the aging effect of loss of material due to leaching. For the management of these aging effects, the applicant proposed to use the Structures Monitoring Program to ensure that these aging effects are properly managed. The Structures Monitoring Program was revised to credit the One-Time Inspection Program to identify selective leaching for these components. The One-Time Inspection Program includes a visual inspection and hardness measurements to identify selective leaching of susceptible components. As stated in LRA Section B2.1.20, the and Structures Monitoring Program scope covers yard structures that are within the scope of license renewal. On the basis of the above discussion and program evaluation, the staff found that the identified aging effect of these structural elements will be properly managed.

The applicant also proposed to use the Structures Monitoring Program to manage potential aging effects of buried concrete electrical duct banks, equipment foundations, support pads, manholes, indoor concrete manhole interior, outdoor concrete equipment foundations, pads, manholes and covers. The applicant noted (LRA Section 3.5 Note 26) that no aging effects requiring management were identified for these structural elements. However, the applicant committed to periodically monitor these structural elements for potential degradation by employing the Structures Monitoring Program. The staff found that the applicant's LRA commitment is reasonable and acceptable. It will ensure that potential degradation of these structural elements will be identified for proper corrective action.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. The staff found that loss of material due to general corrosion and loss of material due to selective leaching in manhole covers and frames can gradually occur in outdoor environments but is not expected to be significant. On the basis of its review of the applicant's program, plant-specific and industry operating experience, the staff found that loss of material due to general corrosion and loss of material due to selective leaching for components in the yard structures are effectively managed using the Structures Monitoring Program. Therefore, the staff found that management of loss of material due to general corrosion and loss of material due to selective leaching in the yard structures using this program is acceptable.

3.5.2.3.10 Cranes, Hoists, and Lifting Devices - Aging Management Evaluation - Table 3.5.2-9

The staff reviewed LRA Table 3.5.2-9, which summarized the results of AMR evaluations for the cranes, hoists, and lifting devices component groups.

The applicant proposed to manage loss of material due to general corrosion and due to wear of structural steel carbon for component type of indoor structural carbon steel, including the bridge and trolley framing, crane rails, monorails, and lifting rigs exposed to an indoor with no external air conditioning environment, by using the Structures Monitoring Program.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. The staff found that loss of material due to general corrosion is minimal in indoor environments. On the basis of its review of the applicant's program, plant-specific and industry operating experience, the staff found that loss of material due to general corrosion and due to wear for components in the cranes, hoists, and lifting devices is effectively managed using the Structures Monitoring Program. Therefore, the staff found that management of loss of material due to general corrosion and due to wear in the cranes, hoists, and lifting devices using this program is acceptable.

The applicant proposed to manage loss of material due to crevice corrosion, MIC, and pitting corrosion of structural stainless steel exposed to borated water, including RV internals lifting rig exposed to treated or borated water with a temperature less than 140 °F, by using the Structures Monitoring Program.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. The staff found that the effect of loss of material of structural steel-stainless material in treated borated water environments is minimal or non-existent. On the basis of its review of the applicant's program, plant-specific and industry operating experience, the staff found that loss of material due to crevice corrosion, loss of material due to MIC, and loss of material due to pitting corrosion for components in the cranes, hoists, and lifting devices are effectively managed using the Structures Monitoring Program. Therefore, the staff found that management of loss of material due to crevice corrosion, loss of material due to MIC, and loss of material due to pitting corrosion in the cranes, hoists, and lifting devices using this program is acceptable.

3.5.2.3.11 Component Supports Commodity Group - Aging Management Evaluation - Table 3.5.2-10

The staff reviewed LRA Table 3.5.2-10, which summarized the results of AMR evaluations for the component supports commodity group component groups.

The applicant proposed to manage loss of material due to general corrosion of structural steel carbon material for component type of indoor structural carbon steel fasteners, including ASME equipment, ASME pipe supports and restraints, and indoor structural carbon steel exposed to indoor with no external air conditioning environment, by using the Structures Monitoring Program.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to general corrosion for components in the component supports commodity group is effectively managed using the Structures Monitoring Program. Therefore, the staff found that management of loss of material due to general corrosion in the component supports commodity group using this program is acceptable.

3.5.2.3.12 Fire Barrier Commodity Group - 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 fire barrier commodity group component groups.

The applicant proposed to manage cracking/delamination due to movement, shrinkage and vibration; loss of material due to abrasion; and separation due to movement, shrinkage, and vibration of calcium silicate board, ceramic fiber, board and mat, and silicone-based materials for component types of indoor calcium silicate board, ceramic fiber, ceramic fiber-board, ceramic fiber-mat, and silicone-based material exposed to indoor with no external air conditioning, by using the Fire Protection Program.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.10. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that the aging effects mentioned above are effectively managed using the Fire Protection Program. Therefore, the staff found that management of these effects in the fire barrier commodity group using this program is acceptable.

The applicant proposed to manage loss of material due to general corrosion of structural steel carbon material for component of indoor structural carbon steel, including fire damper frames and cable tray covers exposed to indoor with no external air conditioning environment, by using the Fire Protection Program.

The staff reviewed the applicant's Fire Protection Program and its evaluation is documented in SER Section 3.0.3.2.10. On the basis of its review of the applicant's plant-specific and industry operating experience, the staff found that loss of material due to general corrosion for components in the fire barrier commodity group is effectively managed using the Fire Protection Program. Therefore, the staff found that management of loss of material due to general corrosion in the fire barrier commodity group using this program is acceptable.

3.5.2.3.13 13.8 KV Switchgear Building Structure - Aging Management Evaluation - Table 3.5.2-12

The staff reviewed LRA Table 3.5.2-12, which summarized the results of AMR evaluations for the 13.8 KV switchgear building structure component groups.

In LRA Table 3.5.2-12, the applicant stated that the AMRs for the 13.8 KV switchgear building structure components do not have aging effects that require management; however, concrete and grout are periodically monitored for potential degradation by using the Structures Monitoring Program.

The staff reviewed the applicant's Structures Monitoring Program, and its evaluation is documented in SER Section 3.0.3.2.19. On the basis of its review, the staff confirmed that the AMR results are consistent with the GALL Report.

3.5.2.3.14 Fuel Oil Pumphouse Structure - Aging Management Evaluation - Table 3.5.2-13

The staff reviewed LRA Table 3.5.2-13, which summarized the results of AMR evaluations for the fuel oil pumphouse structure component groups.

In LRA Table 3.5.2-13, the applicant stated that AMRs for the fuel oil pumphouse structure components do not have aging effects that require management; however, concrete and grout are periodically monitored for potential degradation by using the Structures Monitoring Program.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. On the basis of its review, the staff confirmed that the AMR results are consistent with the GALL Report.

3.5.2.3.15 Gas Turbine Building Structure - Aging Management Evaluation - Table 3.5.2-14

The staff reviewed LRA Table 3.5.2-14, which summarized the results of AMR evaluations for the gas turbine building structure component groups.

In LRA Table 3.5.2-14, the applicant stated that the AMRs for the gas turbine building structure components do not have aging effects that require management; however, concrete and grout are periodically monitored for potential degradation by using the Structures Monitoring Program.

The staff reviewed the applicant's Structures Monitoring Program and its evaluation is documented in SER Section 3.0.3.2.19. On the basis of its review, the staff confirmed that the AMR results are consistent with the GALL Report.

All AMRs in Tables 3.5.2-1 through 3.5.2-14 were evaluated. The staff found them to be acceptable.

Conclusion. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving material, environment, aging effect requiring management, and AMP 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 for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.3 Conclusion

On the basis of its review, the staff concluded that the applicant had demonstrated that the aging effects associated with the containments, structures, and component supports components will be adequately managed so that the intended functions will be maintained for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff also reviewed the applicable FSAR 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 Components

This section of the SER documents the staff's review of the applicant's AMR results for the electrical and instrumentation and controls (I&C) components and component groups associated with the following systems:

- 120 VAC vital instrument power system
- 125 VDC power system
- 4160 VAC power system
- 480 VAC power system
- control rod drive and indication system and nuclear process instrumentation
- miscellaneous AC power and lighting system
- offsite power system
- reactor protection system including anticipated transient without scram
- engineered safety features actuation system
- plant communications system
- 13.8K VAC power system
- radiation monitoring system

3.6.1 Summary of Technical Information in the Application

In LRA Section 3.6, the applicant provided AMR results for electrical and I&C components and component groups. In LRA Table 3.6.1, "Summary of Aging Management Evaluations in Chapter VI of NUREG-1801 for Electrical Components," 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 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 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.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine if the applicant provided sufficient information to demonstrate that the effects of aging for the electrical and I&C 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).

Also, the staff performed an onsite audit 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 AMPs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluations are documented in the staff's PBNP audit and review report and summarized in SER Section 3.6.2.1.

The staff also performed an onsite audit of those AMRs that are consistent with the GALL Report and for which further evaluation is recommended. During the audit, the staff verified that the applicant's further evaluations were consistent with the acceptance criteria in NUREG-1800 Section 3.6.2.2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated July 2001. The staff's audit evaluations are documented in the staff's PBNP audit and review report and summarized in SER Section 3.6.2.2.

The staff performed an onsite audit and 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 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 staff's PBNP audit and review report and 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 FSAR supplement to ensure that they provided an adequate description of the programs credited with managing or monitoring aging for the electrical and I&C system 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 EQ requirements (Item Number 3.6.1-01)	Degradation due to various aging mechanisms	EQ of electric components	TLAA	This TLAA is evaluated in Section 4.8, Environmental Qualification. (See Section 3.6.2.2.1)
Electrical cables and connections not subject to 10 CFR 50.49 EQ requirements (Item Number 3.6.1-02)	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 (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	Cable Condition Monitoring Program	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)
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 3.6.1-03)	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	Cable Condition Monitoring Program	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)
Inaccessible medium-voltage (2 kV to 15 kV) cables (*e.g.*, installed in conduit or directly buried) not subject to 10 CFR 50.49 EQ requirements (Item Number 3.6.1-04)	Formation of water trees, localized damage leading to electrical failure (breakdown of insulation); water trees caused by moisture intrusion	Aging management program for inaccessible medium-voltage cables not subject to 10 CFR 50.49 EQ requirements	Cable Condition Monitoring Program	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 connectors not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage (Item Number 3.6.1-05)	Corrosion of connector contact surfaces caused by intrusion of borated water	Boric acid corrosion	Boric Acid Corrosion Program	Consistent with GALL, which recommends no further evaluation (See Section 3.6.2.1)

The staff's review of the PBNP electrical and instrumentation and controls and associated components followed one of several approaches. One approach, documented in SER Section 3.6.2.1, involves the staff's review of the AMR results for components 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 components 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 for components in the electrical and I&C components that the applicant indicated are not consistent with the GALL Report or are 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 relevant materials, environments, and AERM. The applicant also identified the following programs that manage aging effects related to electrical and I&C components:

- Boric Acid Corrosion Program
- Cable Condition Monitoring Program
- Environmental Qualification 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 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 describe how the information in the tables aligns with the information in the GALL Report. The staff's audit of those AMRs with Notes A through E, indicate the AMR is 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, although different, is 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, although different, is 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 aging management program 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 PBNP 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 have been reviewed and are evaluated in the GALL Report; and (3) identified those aging effects for the electrical and I&C components that are subject to an AMR. On the basis of its review, the staff determined that for AMRs not requiring further evaluation, as identified in LRA Table 3.6.1 (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 found 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 found 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 electrical components. The applicant provided information concerning how it will manage the aging effects of electrical equipment subject to environmental qualification.

The applicant stated that environmental qualification is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The staff's evaluation of this TLAA is addressed in SER Section 4.8, Environmental Qualification of Electric Equipment.

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 reviewed the applicant's evaluation to determine whether it adequately addressed the issues that were further evaluated.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

In LRA Section 3.6.2.2.1, the applicant stated that environmental qualification is a TLAA, as defined in 10 CFR 54.3. Applicants must evaluate TLAAs in accordance with 10 CFR 54.21(c)(i). SER Section 4.8 documents the staff's review of the applicant's evaluation of its TLAA.

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 3.6.2-1, the applicant provided additional details of the results of the AMRs for material, environment, AERM, and AMP considerations that are not addressed in the GALL Report.

As documented under RAI 2.1-1 in SER Section 2.1, by letter dated April 29, 2005, the applicant changed the methodology used to determine the nonsafety-related SCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a)(2). As a result of the implementation of the scoping methodology changes, the applicant identified no changes to LRA Table 3.6.2-1.

In LRA Table 3.6.2-1, the applicant indicated, via Note 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 demonstrated that the effects of aging will be adequately managed so that the intended function will be maintained consistent with the CLB during the period of extended operation.

3.6.2.3.1 Electrical Components - Electrical Commodity Groups - Aging Management Evaluation - Table 3.6.2-1

The applicant identified that AMPs are not required for the following component types:

- high-voltage insulators (offsite power system)
- phase bus (480 VAC, 4160 VAC, and 13.8K VAC power systems)
- transmission conductors (offsite power systems)
- electrical connections not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water leakage outside containment and in an indoor environment with no air-conditioning

Table 3.6-2, below, shows a summary of LRA Table 3.6.2-1 indicating those component types, systems, materials, and environments for which no AMPs have been identified.

Table 3.6-2 Electrical Component Types, Materials, and Environments Without AMPs

Component Type (System)	Material	Environment	Aging Management Program
High-voltage insulators (Offsite Power System)	Cement Metal Porcelain	Outdoor	None Identified
Phase bus (480 VAC, 4160 VAC, and 13.8K VAC Power Systems)	Aluminum Porcelain Bronze Silicone Copper Stainless Steel Fiberglass Steel Noryl	Indoor - with or without Air Conditioning	None Identified

Component Type (System)	Material	Environment	Aging Management Program
Transmission conductors (Offsite Power System)	Aluminum Steel	Outdoor	None Identified
Electrical connections not subject to 10 CFR 50.49 EQ requirements that are exposed to borated water (Some Electrical and I&C Systems)	Connections and Connector Pins - Various Metals	Containment (External), Indoor - No Air-conditioning (external)	None Identified

The applicant stated, per Note J in LRA Table 3.6.2-1, that for the above components neither the component nor the material and environment combination is evaluated in GALL.

The staff's review of LRA Section 3.6 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.

RAI 3.6.2.1-1. In RAI 3.6.2.1-1, dated November 18, 2004, the staff requested the applicant to provide justification for not including the above components in the AMPs, or provide AMPs for the above components.

During a telephone conference of its response dated January 25, 2005, the applicant agreed to delete Note J in LRA Table 3.6.2-1. However, the applicant insisted that no AMPs are required for above components. The staff's RAI for each component listed above, the justification provided by the applicant for not providing AMPs for the above components, and the staff evaluation, is as follows:

High-Voltage Insulators (Offsite Power System). The staff reviewed the high-voltage insulators components, environment, and AMP.

RAI 3.6.2.1-2. In RAI 3.6.2.1-2, dated November 18, 2004, the staff requested the applicant to explain why an AMP for high-voltage insulators is not needed.

In its response, dated January 25, 2005, the applicant stated:

> Various airborne particulate contaminants such as industrial effluents, winter road-salt, and dust can contaminate insulator surfaces. Due to the location of PBNP in a rural environment with no major industry in close proximity, contamination from industrial effluents is not significant. No major traffic runs near the switchyard to make winter road-salt airborne. Lake Michigan is a fresh-water lake and therefore there is no salt spray that can affect the insulators. The buildup of any other surface contaminants is gradual and would be washed away by rainfall or snow, which is seasonal in nature, and cumulative buildup is not expected. The glazed insulator surface aids this contamination removal. Operating experience of over thirty years at PBNP has shown that this is true. Therefore, surface contamination of high-voltage insulators is not an AERM at PBNP.

On the basis of the above discussion, the staff found this justification acceptable because the applicant provided operating experience that demonstrates that an AMP is not needed. The staff's concern described in RAI 3.6.2.1-2 is resolved.

Phase bus (480 VAC, 4160 VAC, and 13.8K VAC Power Systems). The staff reviewed the phase bus (480 VAC, 4160 VAC, and 13.8K VAC power systems) components, environment, and AMP.

RAI 3.6.2.1-3. In RAI 3.6.2.1-3, dated November 18, 2004, the staff requested the applicant to explain why an AMP for bus ducts is not needed. Conforming to INs 89-64, 98-36, and 2000-4, the staff requested the applicant to consider providing an AMP.

In its response, dated January 25, 2005, the applicant stated:

> The phase bus in-scope for license renewal at PBNP is fully enclosed and installed in the control building, turbine building, 13.8K VAC switchgear building, gas turbine building, and outdoors (weatherproof enclosures). Where enclosure vents are part of the design, filters are provided to ensure cleanliness. No phase bus is installed in the containment, facade, or the PAB. Thus, no phase bus is installed in an area where it is exposed to debris or dust, radiation, or high temperatures. The environments for phase bus in the control building and 13.8K VAC switchgear buildings are indoors, with air conditioning. Phase bus between non-vital switchgear in the turbine building is routed beneath the ceiling of the control building. Thus exposure to moisture is eliminated in these locations. Phase bus located outdoors is weatherproof designed for those locations, integral to the switchgear connections to the high-voltage and low-voltage station auxiliary transformers for each unit, and inspected and maintained as part of those active components, which includes periodic inspections and cleaning. Where appropriate, heaters are installed to prevent condensation internal to the bus enclosure. Therefore, exposure to moisture due to water ingress or condensation is mitigated.
>
> Carbon steel hardware (bolts, washers, nuts and clamp screws) was factory coated (plated or galvanized) to inhibit corrosion and is used only in the bus duct enclosure assembly. Stainless steel hardware used in bus electrical connections (copper bus bar and fittings) has no age-related degradation due to moisture in either indoor or outdoor environments. Bolting is typically done using Belleville or lock washers to maintain contact pressure. After more than 33 years in these service environments, minimal or no signs of corrosion or loss of material have been observed and no functional loss has been observed. Therefore, loss of material for steel hardware due to corrosion or oxidation, and loosening of connecting hardware are not applicable aging effects that would lead to a loss of intended function for the phase bus for the period of extended operation.
>
> Phase bus is supported by static structural components such as concrete foundations, building steel, and switchgear cabinets. Structural support and enclosures are considered part of the Component Support Commodity Group for aging management.
>
> Phase bus is connected to static equipment that does not normally vibrate such as switchgear, transformers and disconnect switches; therefore, loosening of bolted connections is not an aging effect requiring management. Vibration is not an applicable

stressor for these connections to non-moving and non-vibrating equipment and supports, and aging effects due to vibration are not applicable. Flexible connectors are used throughout the plant in connections between phase bus and different sections of switchgears.

The one section of phase bus connected to a potential source of vibration connects to the non-vital gas turbine generator through flexible conductors. These flexible conductors prevent generator vibrations from propagating into the rigid phase bus. Internal to the enclosures the bus is supported by porcelain insulators, which have no aging effects in their controlled environments. Flexible connectors are used throughout the plant in connections between phase bus and different sections of switchgear. In addition this equipment is only run for testing and as a (typically) summer peaking unit. Therefore, the associated bus will have far less than 40 years of actual operation at the end of the period of an extended license. In addition, vibration is not an applicable stressor even for phase bus that is connected to equipment that may move, and aging effects due to vibration are not applicable. Periodic gas turbine maintenance, inspections, and testing include this phase bus in their scope and would address any equipment issue found.

All of the bus and flexible connections are copper, silver-plated and/or coated with anti-oxidant grease. Copper bus, solid and flexible connectors and ground straps are highly conductive and make a good contact surface. To prevent the formation of oxide on connection surfaces, the connections were factory silver plated, cleaned to remove any existing oxide, and covered with grease to prevent air from contacting the surface before assembly. The grease excludes air from the connection after assembly, precluding oxidation of the surface, thereby maintaining good conductivity between the bus connecting surfaces. The grease is a consumable that is replaced during each routine maintenance of the bus.

The referenced NRC Information Notices (IN) were re-examined during the RAI phase of the NRC review of the PBNP LRA. Specific attention was directed to the questions asked by NRC reviewers regarding why PBNP was not proposing a bus bar aging management program.

- IN 89-64 was previously examined and considered in the Operating Experience section of the PBNP electrical AMR. The failures noted in this IN were results of either an accumulation of water or debris, inadequate design, manufacturing defect, or an environment that caused deterioration of insulation. A review of the construction, materials, and bus bar environments at PBNP concluded that no aging effects from this IN were applicable to phase bus at PBNP.

- IN 98-36 was examined and excluded from the AMR since it addresses event-driven faults caused by impact of an external foreign object (roofing materials), direct water leakage or moisture intrusion, inadequate design or assembly, or mis-operation, including an event at PBNP where a bus duct heater breaker was open for an extended period of time (exceeding one year). These are all events due to causes other than aging. Therefore, no aging effects from this IN were applicable to phase bus at PBNP.

- IN 2000-14 was examined and excluded from the AMR since it addresses a fault-based event, not aging. Multiple non-Class 1E buses were lost due to co-location (crossing) of bus duct with an initiating failure caused by a center bus bar overheating at a splice joint, causing a PVC boot to smoke, and heat induced failure of fiberglass insulation on adjacent phases causing phase-to-phase arcing. A combination of poor design factors was the root cause: mixture of aluminum and copper bus bars, poor silver-plating on the aluminum bar, corrosion induced on the aluminum bar due to the PVC boot material, and undersized splice plates of wrong material not centered on the bus bar, reducing contact area. Splice plates were undersized aluminum rather than larger copper plates, used by the vendor during tests to determine design temperature rise to meet IEEE 37.20-1969 of 65 °C. The bus was routinely loaded to 2100 amps and actual worst case loaded to 2250 amps, its rating limit. This caused the bus to exceed the design conditions for some time. Torque relaxation likely occurred due to the overheating and bus bar expansion and contraction. A 1995 explosion of an auxiliary transformer that physically displaced the bus could have also contributed to the low torque values. Inability to isolate the bus caused a small event to propagate to multiple buses and major damage.

  The only non-Class 1E buses in-scope for PBNP are in the 13.8K VAC system. The system was constructed in 1988 - 1991 and is located separate from all other bus in a dedicated building. Bus bar at PBNP is all copper with proper sized and located connections, per vendor design (PBNP was a turn-key plant by Westinghouse, which supplied and installed the original switchgear and bus). Bus duct are not co-located with other bus duct from the same or different parts of any electrical systems and are able to be isolated, thus fault propagation is not an issue. Bus bar loading is low compared to bus bar rating and thus expansion and contraction is minimized to within the range of the design capacity of the lock washers and Belleville washers.

The PBNP bus bar configuration is represented by all copper bus, properly assembled to original vendor specifications, and installed in a dry, clean environment. Therefore, there are no applicable aging effects for the phase bus that are in-scope for license renewal at PBNP when exposed to their service conditions for the extended period of operation.

The staff reviewed the above response and found that sufficient justification had not been provided for preventing cracking or failure of busbar insulation as observed at many plants noted in IN 89-64. Similarly, the loosening of terminal connections resulting from the thermal cycling (as indicated in the Sandia 96-0344 report) was not adequately addressed in the above response.

The staff discussed the applicant's needs regarding an AMP for bus (phase) duct with at least the following essential components.

- Parameters Monitored/Inspected: A sample of accessible bolted connections will be checked for proper torque. This program will also inspect the internal portion of the bus duct for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The bus insulation system will be inspected for signs of embrittlement, cracking, melting, swelling or discoloration, which may indicate overheating or aging degradation. The (internal) bus supports will be inspected for structural integrity and signs of cracks.

- Detection of Aging Effects: This program will be completed before the end of the initial 40-year license term and every 10 years thereafter. This is an adequate period to preclude failures of the bus ducts since experience has shown that aging degradation is a slow process. A 10-year inspection frequency will provide two data points during a 20-year period, which can be used to characterize the degradation rate.
- Acceptance Criteria: Bolted connections must meet the minimum torque specifications. bus ducts are to be free from unacceptable visual indications of surface anomalies, which suggest that conductor insulation degradation exists.

During a meeting, on February 15, 2005, the staff indicated and the applicant agreed, that the applicant's response required further clarification.

In its response, a clarification letter dated March 15, 2005, the applicant stated that the metal-enclosed phase bus in the power systems within the scope of license renewal had not shown a potential for aging that requires management. Nonetheless, the applicant committed to perform periodic inspections of the bus duct as part of the Periodic Surveillance and Preventive Maintenance Program. These periodic visual inspections will look for signs of insulation cracking, corrosion, debris, excessive buildup, moisture, water intrusion, and insulation discoloration.

On the basis of the above discussion, the staff found this acceptable. The applicant provided a commitment, which provides reasonable assurance that aging effects will be adequately managed. The staff's concern described in RAI 3.6.2.1-3 is resolved.

Transmission Conductors (Offsite Power Systems). LRA Section 2.5.1, under the sub-heading, "Transmission Conductors," states that the transmission conductor connections to active disconnect switches, power circuit breakers, and transformers are inspected using thermography and maintained along with and as part of the disconnect switch, power circuit breaker or transformer and, therefore, meet the definition of an active component as discussed in the Statement Of Considerations (SOC) that accompanied the Rule.

RAI 3.6.2.1-4. The reason (Note J) provided in LRA Table 3.6.2-1 for not including transmission conductors in any AMP was different from the explanation provided in LRA Section 2.5.1. In RAI 3.6.2.1-4, dated November 18, 2004, the staff requested the applicant to provide an explanation for the discrepancy between LRA Table 3.6.2-1 and LRA Section 2.5.1 for transmission conductors.

In a telephone conference discussion of its response dated January 25, 2005, the applicant agreed to delete Note J against transmission conductors in LRA Table 3.6.2-1 to resolve this discrepancy. On the basis of its review, the staff found acceptable the elimination of Note J from LRA Table 3.6.2-1. The staff's concern described in RAI 3.6.2.1-4 is resolved.

Electrical Connections Not Subject to 10 CFR 50.49 EQ Requirements That Are Exposed to Borated Water Leakage. The staff reviewed the electrical connections not subject to EQ requirements, components, environment, and AMPs.

RAI 3.6.2.1-5. In RAI 3.6.2.1-5, dated November 18, 2004, the staff requested the applicant to justify why components located indoors but outside of containment were not included in the Boric Acid Corrosion Program, per LRA Table 3.6.2-1.

In its email, dated December 9, 2004, preceding its formal response, dated January 25, 2005, the applicant stated:

> Piping systems containing borated water are located in three physical areas of the plant: the Unit 1 containment, the Unit 2 containment, and the Primary Auxiliary Building. The environment of Borated Water Leaks (External) in Table 3.6.2-1 applies to any location in all three areas where in-scope electrical and Instrumentation and Controls (I&C) cables and connections are located and may be exposed to borated water leakage, both in and out of containment. Therefore, Table 3.6.2-1 denotes that the Boric Acid Corrosion Program applies to the in-scope electrical components in all of these locations.
>
> The connections in these physical locations are identified in Table 3.6.2-1 as also having normal environments away from sources of borated water, Containment (External) and Indoor - No Air-Conditioning (External) in the Primary Auxiliary Building, where no AERM is expected. These materials and environments were considered in our AMR, and for the locations away from boric acid leaks no AERM were identified. NUREG-1801 does not have a specific program for these components, except as part of XI.E1; therefore, Note J was referenced. Both the non-boric acid environments and Note J could be omitted if that eliminates the confusion in this entry.

On the basis of its review, the staff found acceptable the elimination of Note J from LRA Table 3.6.2-1. The staff's concern described in RAI 3.6.2.1-5 is resolved.

Switchyard Buses and Connections (Offsite Power System). The staff noted that in LRA Table 3.6.2-1, it is indicated that "Switchyard buses and connections (Offsite Power System)" will be covered under Cable Condition Monitoring Program. However, Cable Condition Monitoring Program does not include switchyard buses and connections. Also, in LRA Section 2.5.1, under the sub-heading, "Switchyard Bus," the applicant stated that the review of switchyard bus includes the switchyard bus and the hardware used to secure the bus to a high-voltage insulator. This includes corona rings and other similar fixtures that are standard design features of the switchyard bus. The applicant further stated that the bus connection to an active disconnect switch is inspected using thermography and maintained along with and as part of the disconnect switch and, therefore, meets the definition of an active component as discussed in the SOC that accompanied the Rule.

RAI 3.6.2.1-6. In RAI 3.6.2.1-6, dated November 18, 2004, the staff requested the applicant to provide an explanation for the discrepancy between LRA Table 3.6.2-1 and LRA Section 2.5.1 regarding switchyard buses and connections.

In its response, dated January 25, 2005, the applicant stated that:

> The circuit switchers are the boundary components between in-scope and not-in-scope components in the switchyard. The Cable Condition Monitoring Program covers the aging management of the connecting control cabling for the switchgear, transformers,

and circuit switchers located in the switchyard that are in-scope for license renewal. The only switchyard bus and fixtures in-scope are directly connected to the circuit switchers and are maintained as part of these active components. High-voltage insulators were separately evaluated as supports for these components. All switchyard bus, fixtures, supports, and other components beyond the circuit switchers are not-in-scope. The description of the types of inspection used are typical of normal plant component condition monitoring activities and do not constitute an AMP. No aging is expected for these components. Operating experience of over thirty years at PBNP has shown that this is true.

On the basis of its review and RAI response, the staff found the elimination of Note J from LRA Table 3.6.2-1 is acceptable to resolve this discrepancy. The staff's concern described in RAI 3.6.2.1-6 is resolved.

Conclusion. On the basis of its review, the staff found that the applicant had appropriately evaluated AMR results involving material, environment, AERM, and AMP combinations that are not evaluated or addressed 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

On the basis of its review, the staff concluded that the applicant had demonstrated that the aging effects associated with the electrical and I&C systems components 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 FSAR supplement program summaries and concluded that they adequately describe the AMPs credited for managing aging of the electrical and I&C systems, as required by 10 CFR 54.21(d).

3.7 Conclusion for Aging Management Review Results

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 FSAR supplement program summaries and concluded that the FSAR supplement adequately describes the AMPs credited for managing aging as required by 10 CFR 54.21(d).

With regard to these matters, the NRC staff has 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 PBNP current licensing basis 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 addresses the identification of time-limited aging analyses (TLAAs). Nuclear Management Company, LLC (the applicant) discusses the TLAAs in LRA Sections 4.2 through 4.8. 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).

TLAAs are certain plant-specific safety analyses that involve time-limited assumptions defined by the current operating term. Pursuant to Title 10, Section 54.21(c)(1), of the *Code of Federal Regulations*, the applicant for license renewal must provide a list of TLAAs, as defined in 10 CFR 54.3.

In addition, pursuant to 10 CFR 54.21(c)(2), an applicant must 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 Point Beach Nuclear Plant (PBNP) Units 1 and 2 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) and industry license renewal related documents including the Standard Review Plan for License Renewal (SRP-LR) Chapter 4, NEI 95-10, Statements of Consideration for 10 CFR 54, Westinghouse Owners Group Generic Technical Reports, and previously submitted LRAs for other plants. The CLB includes the FSAR, Technical Specification, NRC SERs, docketed correspondence, and NRC regulatory commitments and requirements.

The applicant listed the following applicable TLAAs in LRA Table 4.1-2, "Time-Limited Aging Analyses":

- reactor vessel irradiation embrittlement
- fatigue
- fracture mechanics analysis
- loss of preload
- neutron absorber
- wear
- environmental qualification

Pursuant to 10 CFR 54.21(c)(2), the applicant identified exemptions granted under 10 CFR 50.12 that were based on TLAAs, as defined in 10 CFR 54.3. The applicant listed the following exemptions associated with TLAAs in LRA Table 4.1-1, "Active Exemptions Associated with Time-Limited Aging Analysis":

- determination of adjusted/indexing reference temperatures for pressurized thermal shock TLAA
- use of the latest Edition of supplemental ASTM E185-98 for pressurized thermal shock TLAA
- alternative testing methods of determination of fracture toughness for pressurized thermal shock TLAA

4.1.2 Staff Evaluation

In LRA Section 4.1, the applicant identified the TLAAs applicable to Units 1 and 2 and discussed exemptions based on these TLAAs. The staff reviewed the information to determine whether the applicant had provided adequate information to meet the requirements of 10 CFR 54.21(c)(1) and (c)(2).

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

(1) involve systems, structures, and components 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 (*i.e.*, 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)

(6) are contained or incorporated by reference in the CLB

The applicant provided a list of common TLAAs from NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plant," dated July 2001. The applicant listed those TLAAs that are applicable to Units 1 and 2 in LRA Table 4.1-2, "Time-Limited Aging Analyses."

As required by 10 CFR 54.21(c)(2), an applicant must provide a list of all exemptions granted under 10 CFR 50.12 that are determined to be based on a TLAA and that are evaluated and justified for continuation through the period of extended operation. In its LRA, the applicant stated that it performed a search of the CLB and evaluated each exemption in effect for TLAA applicability. The applicant also identified TLAA-based assumptions.

The staff review of LRA Section 4.1 identified areas in which additional information was necessary to complete the review of the listed TLAAs and plant-specific exemptions. The applicant responded to the staff's requests for additional information (RAI) as discussed below.

RAI 4.1.1-1. The applicant stated that industry license renewal related documents were searched to identify a list of known TLAAs that could be applicable to PBNP. This potential list of TLAAs is itemized in LRA Section 4.1.1.1. The applicant listed the TLAAs applicable in LRA Table 4.1-2. In RAI 4.1.1-1, dated November 17, 2004, the staff requested the applicant to indicate whether there are any calculations or analyses at PBNP that address the topics listed in LRA Section 4.1.1.1 that were not included in LRA Table 4.1-2.

In its response, dated January 25, 2005, the applicant stated that there are no calculations or analyses at PBNP that address the topics listed in LRA Section 4.1.1.1 that were not included in LRA Table 4.1-2. Based on the applicant's response, the staff concluded that all appropriate TLAAs applicable to PBNP were listed, and the staff concluded that the applicant's response to RAI 4.1.1-1 is acceptable. The staff's concern described in RAI 4.1.1-1 is resolved.

RAI 4.1.1-2. LRA Section 4.1.2, pursuant to 10 CFR 54.21(c)(2), listed the plant-specific exemptions granted pursuant to 10 CFR 50.12. This section described the exemptions and why they were still needed. In RAI 4.1.1-2, dated November 17, 2004, the staff requested the applicant to provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

In its response, dated January 25, 2005, the applicant stated that it had withdrawn the request for exemptions to 10 CFR 50.61, and Appendices G and H to 10 CFR Part 50, in its letter dated August 3, 2004. In its letter, dated October 25, 2004, the applicant further stated that it revised LRA Section 4.1.2 to state that "No TLAA related exemptions granted pursuant to 10 CFR 50.12 were identified." The staff reviewed the subject letter and noted that the applicant withdrew its TLAA-related exemptions. Based on the applicant's response that no TLAA-related exemptions exist, the staff considers that the applicant's response to RAI 4.1.1-2 is acceptable. The staff's concern described in RAI 4.1.1-2 is resolved.

4.1.3 Conclusion

On the basis of its review and the applicant's response to the staff's RAIs, the staff concluded that the applicant provided an acceptable list of TLAAs as required by 10 CFR 54.21(c)(1). In addition, based on the applicant's RAI responses, the staff concluded that no exemptions were granted on the basis of a TLAA pursuant to 10 CFR 50.12 and, therefore, the requirement under 10 CFR 54.21(c)(2) does not apply.

4.2 Reactor Vessel Irradiation Embrittlement

Neutron embrittlement is a significant aging mechanism for all ferritic materials that have a neutron fluence greater than 10^{17} n/cm^2 (E>1.0 MeV). The relevant calculations use predictions of the cumulative damage to the reactor vessel (RV) from neutron embrittlement, and were originally based on the 40 calendar-year plant license. The reactor pressure vessel (RPV) contains the core fuel assemblies and is made of thick steel plates that are welded together. Neutrons from the fuel in the reactor irradiate the vessel as the reactor is operated and change the material properties of the steel. The most pronounced and significant changes occur in the material property known as fracture toughness.

Fracture toughness is a measure of the resistance to crack extension in response to stresses. A reduction in this material property due to irradiation is referred to as embrittlement. The largest amount of embrittlement usually occurs at the section of the vessel's wall closest to the reactor fuel, otherwise referred to as the vessel's beltline. The rate at which the vessel's steel embrittles also depends on its chemical composition. The amounts of two elements in the steel, specifically copper and nickel, are the most important chemical elements in determining how sensitive the steel is to neutron irradiation.

The applicant identified three analyses affected by irradiation embrittlement that were identified as TLAAs. These analyses are discussed in LRA Section 4.2. The analyses identified as TLAAs are:

(1) pressurized thermal shock (PTS)
(2) reactor vessel upper shelf energy (USE)
(3) pressure/temperature (P-T) limit curves

The corresponding subsections of this SER (4.2.1 - 4.2.3, respectively) present the staff's evaluation of the RV irradiation embrittlement TLAAs.

4.2.1 Reactor Vessel Pressurized Thermal Shock

4.2.1.1 Summary of Technical Information in the Application

Section 50.61 of 10 CFR provides the fracture toughness requirements protecting the RVs of pressurized water reactors against the consequences of PTS. Applicants are required to perform an assessment of the RV materials projected values of the PTS reference temperature (RT_{PTS}), through the end of their operating licenses. The Rule requires each applicant to calculate the end-of-life RT_{PTS} value for each material located within the beltline of the reactor pressure vessel. The RT_{PTS} value for each beltline material is the sum of the unirradiated nil ductility reference temperature (RT_{NDT}) value, a shift in the RT_{NDT} value caused by exposure to high-energy neutron irradiation of the material (*i.e.*, ΔRT_{NDT} value), and an additional margin value to account for uncertainties (*i.e.*, M value). Section 50.61 of 10 CFR also provides screening criteria against which the calculated values are to be evaluated. RV beltline base-metal materials (forging or plate materials) and longitudinal (axial) weld materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 270 °F. RV beltline circumferential weld materials are considered to provide adequate protection against PTS events if the calculated RT_{PTS} values are less than or equal to 300 °F.

Regulatory Guide (RG) 1.99, Revision 2, provides an expanded discussion regarding the calculations of the shift in the RT_{NDT} value caused by exposure to high-energy neutron irradiation and the margin value to account for uncertainties. In this RG, the shift in the RT_{NDT} value caused by exposure to high-energy neutron irradiation is the product of a chemistry factor and a fluence factor. The fluence factor is dependent upon the neutron fluence, and the chemistry factor may be determined from surveillance material or from the tables in the RG. If the RV beltline material is not represented by surveillance material, its chemistry factor and the shift in the RT_{NDT} value caused by exposure to high-energy neutron irradiation may be determined using the methodology documented in position 1.1 and the tables in this RG. The chemistry factor determined from the tables in the RG depends upon the amount of copper and nickel in the beltline. If the RV beltline material is represented by surveillance material, its chemistry factor may be determined from the surveillance data using the methodology documented in position 2.1 of this RG. Section 50.61 of 10 CFR contains methods of determining RT_{NDT} values equivalent to RG 1.99, Revision 2.

In LRA Section 4.2.1, the applicant discussed the PTS analysis for Units 1 and 2, using the criteria of 10 CFR 50.61.

RT_{PTS} values were calculated for the inside surface of the beltline region materials for the Unit 1 RPV using Charpy-based fracture toughness evaluations in accordance with the methods of 10 CFR 50.61 for a 53 effective full power year (EFPY) operating period. The RT_{PTS} values for the beltline region materials at the end of the period of extended operation were calculated to be lower than the applicable screening criteria values established in 10 CFR 50.61.

RT_{PTS} values were calculated for the inside surface of the beltline region materials for the Unit 2 RPV using Charpy-based fracture toughness evaluations in accordance with the methods of 10 CFR 50.61 for a 53 EFPY operating period. The RT_{PTS} values for the beltline region materials at the end of the extended period of operation were calculated to be lower than the applicable screening criteria values established in 10 CFR 50.61, with the exception of the intermediate-to-lower shell circumferential weld. The intermediate-to-lower shell circumferential weld is the limiting Unit 2 RPV weld.

In its revised submittal, letters dated September 10 and October 25, 2004, the applicant provided information about the plan for addressing PTS concerns prior to exceeding the screening criteria. Paragraph (c)(iii) of 10 CFR 54.21 allows the applicant to demonstrate that the effects of aging on the intended functions of the SSC will be adequately managed for the period of extended operation. This option permits an applicant to elect not to extend the existing TLAA.

4.2.1.2 Staff Evaluation

The staff's review of LRA Section 4.2.1 identified areas in which additional information was necessary to complete the review of the PTS evaluation. The applicant responded to the staff's RAIs as discussed below.

In the license renewal revised submittal, the applicant provided Unit 1 RT_{PTS} analyses for the materials in the PBNP reactor vessel beltline. Table 4.2.1-1 in the submittal provides the chemistry factor and the predicted RT_{PTS} value through 53 EFPY for each forging and weld in the PBNP reactor vessel beltline.

In order to verify the predicted RT_{PTS} value through 53 EFPY, the staff used the neutron values provided by the applicant. The neutron fluence calculation used END/B-VI scattering cross section data set. The calculated fluence projections were determined using methods consistent with RG 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence."

In addition to the plant-specific neutron exposure calculations, dosimetry sets from 3 in-vessel and 20 ex-vessel sensor sets irradiated at Unit 1, and 4 in-vessel and 20 ex-vessel sensor sets irradiated at Unit 2 were also reanalyzed using dosimetry evaluation methodologies that follow the guidance provided in RG 1.190. The results of these dosimetry re-evaluations were then used to validate the calculational models that were applied in the plant-specific neutron transport analysis of the Point Beach RPVs. The projected fluence values for the Units 1 and 2 vessel at the end of extended life, 53 EFPY, are 4.71×10^{19} n/cm^2 and 4.85×10^{19} n/cm^2 respectively. The fluence projections were revised in 2004 to account for actual unit operational history (including the 1.7 percent mini-uprate performed in 2003), and a planned full unit uprate to 1678 MWt in 2008. These fluence projections were based on historical operational data, and forecasted uprated (1678 MWt) power conditions using a low-low leakage fuel management pattern without the presence of hafnium power suppression absorber rods. However, the applicant also made a commitment that PBNP will continue operation with hafnium absorber assemblies in service until the resolution of the Unit 2 intermediate-to-lower shell girth weld PTS issue via an alternative analysis methodology.

The applicant's projected fluence is calculated fluence, not the best-estimate fluence, and the calculation is based on RG 1.190; therefore, the staff accepts the fluence calculation methodology.

The staff independently evaluated RT_{PTS} values for Unit 1 and identified that the values are below the 10 CFR 50.61 screening criteria. Therefore, the staff concluded that PBNP Unit 1 RV will meet the requirements of 10 CFR 50.61 through the expiration of the period of extended operation.

RT_{PTS} values for Unit 2 are lower than the screening criteria values established in 10 CFR 50.61 for the current license period. The staff independently verified the applicant's RT_{PTS} values provided in LRA Table 4.2.1-2 and concluded that the RT_{PTS} values will be below the PTS screening criteria except for the intermediate-to-lower shell girth weld. The intermediate-to-lower shell girth weld will exceed the PTS screening criteria for the Unit 2 RV during the period of extended operation. The screening criteria established in 10 CFR 50.61 will be exceeded for the limiting Unit 2 intermediate-to-lower shell girth weld at a neutron fluence of 3.31×10^{19} n/cm^2. The fluence projections also indicate that the limiting weld will experience this fluence at 38.1 EFPYs. Using a long-term capacity factor of 95 percent, this fluence would be achieved in late 2017.

If a reactor vessel is projected to exceed the PTS screening criteria, 10 CFR 50.61(b)(3) requires the applicant to implement a flux reduction program that is reasonably practicable to avoid exceeding the PTS screening criteria. If the flux reduction program does not prevent the reactor vessel from exceeding the PTS screening criterion at the end of life, the applicant can choose between the two options in 10 CFR 50.61 to meet PTS requirements. The applicant can submit a safety analysis pursuant to 10 CFR 50.61(b)(4) to determine what, if any, modifications to equipment, systems, and plant operation are necessary to prevent failure of the reactor vessel from a postulated PTS event. The other option is to perform a thermal-annealing treatment of the reactor vessel pursuant 10 CFR 50.61(b)(7) to recover fracture toughness. Section 50.61 of 10 CFR requires details of the approach selected to be submitted for NRC approval at least three years before the reactor vessel is projected to exceed the PTS screening criteria.

The license renewal applicant that chooses to use the 10 CFR 54.21(c)(1)(iii) option for managing the reactor vessel PTS TLAA must provide an assessment of the CLB TLAA for PTS, a discussion of the flux reduction program implemented in accordance with 10 CFR 50.61(b)(3), if necessary, and an identification of the viable options that exist for managing the aging effect in the future ("Pressurized Thermal Shock Analyses for Renewal of Certain Nuclear Power Plant Operating Licenses," Executive Director Memo to Commissioners, dated May 27, 2004, ML 041190564).

RAI 4.2-1. On August 3, 2004, the staff met with the applicant to discuss the RV integrity issues related to the license renewal application. In that meeting, the staff stated that when the applicant provides its revised RPV integrity analyses, one defined "operational basis" for projecting fluence values to be used for PTS, USE, and P-T limit TLAAs must be chosen.

In its letter dated September 10, 2004, the applicant revised LRA Sections 4.1.2, 4.2.1, 4.2.2, 4.2.3, and Appendices A15.2.18, A15.4.1, A15.5, and B2.1.18. The staff noted from the revised sections that the applicant did not provide one defined operational basis. The fluence projections used for PTS are different from the fluence projections used for P-T limits and the USE evaluation. In RAI 4.2-1, dated September 23, 2004, the staff requested the applicant to modify its evaluation of reactor vessel TLAAs (P-T, USE, RT_{PTS}) using the same projected fluence basis.

RAI 4.2-2. On August 3, 2004, the staff also discussed that once the applicant chooses its calculational basis, a PTS analysis should be submitted in accordance with the methodology in 10 CFR 50.61 for both units. The analysis must specifically state when Unit 2 will exceed the PTS screening criteria.

In its letter dated September 10, 2004, the applicant revised Sections 4.1.2, 4.2.1, 4.2.2, 4.2.3, and Appendices A15.2.18, A15.4.1, A15.5, and B2.1.18. As a followup to RAI 4.2-2, the staff requested the applicant to provide the estimated EFPY and calendar year at which RT_{PTS} values for Unit 2 will exceed the screening criteria.

Recognizing that one of the Unit 2 RV welds will exceed the 10 CFR 50.61 PTS screening criteria, in its response to the above RAIs, by letter dated October 25, 2004, the applicant chose to use the 10 CFR 54.21(c)(1)(iii) option for managing the reactor vessel PTS TLAA. Accordingly, the applicant provided a discussion of the flux reduction program implemented in accordance with 10 CFR 50.61(b)(3) and also identified other viable options that exist for managing the aging effect in the future.

In both letters, the applicant made the following commitments:

- PBNP will continue to implement the low-low leakage loading fuel management pattern to minimize the limiting weld fluence. In addition, PBNP will continue operation with hafnium absorber assemblies in service until the resolution of the Unit 2 intermediate-to-lower shell girth weld PTS issue via an alternative analysis methodology.
- Documentation of a flux reduction program and other options, as necessary, allowed by 10 CFR 50.61(b) for the Unit 2 RPV intermediate-to-lower shell girth weld, will be completed within one-year of receipt of the extended license. Documentation within this

time frame will support submittal of any required safety analysis at least three years prior to the time frame that RT_{PTS} for Unit 2 is projected to exceed the screening criteria.

- If acceptable PTS results cannot be provided prior to end of life (EOL) with alternative analysis techniques, the PBNP flux reduction program will evaluate the feasibility and practicality of pursuing additional aggressive flux reduction measures prior to EOL, such as the insertion of part-length shielded fuel assemblies.

Based on the above discussion, the staff found that the applicant's response and commitments are acceptable. The applicant's commitments will ensure that the aging effects will be managed during the period of extended operation. The staff's concerns described in RAIs 4.2-1 and 4.2-2 are resolved.

4.2.1.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 FSAR supplement summary description of PTS in LRA Section A15.4.1. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on PTS and, is therefore, acceptable.

4.2.1.4 Conclusion

The staff reviewed the applicant's TLAA on PTS as summarized in Section 4.2.1, and determined that the RV beltline materials at Unit 1 will continue to comply with the staff's requirements for PTS in 10 CFR 50.61 throughout the period of extended operation as required by 10 CFR 54.21(c)(1)(ii).

In addition, the staff reviewed the applicant's TLAA on PTS as summarized in LRA Section 4.2.1 and concluded that the applicant's TLAA for PTS at Unit 2 will continue to comply with the staff's requirements for PTS in accordance with 10 CFR 50.61 throughout the period of extended operation as required by 10 CFR 54.21(c)(1)(ii). Although one circumferential weld in the beltline region exceeds PTS screening criteria, the staff concluded 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)(iii).

The staff also concluded that the FSAR supplement, for both Units 1 and 2, contains an appropriate summary description of the TLAA on PTS for the period of extended operation, as required by 10 CFR 54.21(d).

4.2.2 Reactor Vessel Upper Shelf Energy

Appendix G to 10 CFR Part 50 requires that reactor vessel beltline materials have Charpy USE values in the transverse direction for the base metal and along the weld for the weld material of no less than 75 ft-lb (102 J) initially, and must maintain Charpy USE values throughout the life of the vessel of no less than 50 ft-lb (68 J). However, in accordance with Appendix G, paragraph IV.A.1.a, Charpy USE values below these criteria may be acceptable if it is demonstrated, in a manner approved by the Director, Office of Nuclear Reactor Regulation (NRR), that the lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by ASME Code Section XI, Appendix G.

RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," provides an expanded discussion regarding the calculations of Charpy USE values and describes two methods for determining Charpy USE values for RV beltline materials, depending on whether or not a given RV beltline material is represented in the plant's RV material surveillance program (*i.e.*, 10 CFR Part 50, Appendix H 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 two or more 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 that the percentage drop in Charpy USE is dependent upon the amounts of copper 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.

4.2.2.1 Summary of Technical Information in the Application

The applicant indicated that calculations have shown that the vessel beltline Charpy USE for the limiting weld will be less than 50 ft-lb based on RG 1.99, Revision 2. Consequently, a fracture mechanics evaluation was performed to examine the USE values in the limiting weld. The evaluation examined the USE values for EOL extension conditions. The USE in the PBNP fracture mechanics evaluation is reported in J-R (J Resistance) values with units in lb/in. The J-R ratio methodology is described in B & W Owners Reactor Vessel Working Group reports BAW-2178A, "Low Upper Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B & W Owners Reactor Vessel Working Group for Level C & D Service Loads," and BAW-2192PA "Low Upper Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B & W Owners Reactor Vessel Working Group for Level A & B Service Loads," both dated April 1994. The staff reviewed and approved both these reports for referencing in licensing applications in separate safety evaluations on March 29, 1994. The analysis demonstrates that the limiting RV beltline weld satisfies the ASME Code requirements of Appendix K for ductile flaw extensions and tensile stability using projected low upper-shelf Charpy impact energy levels for the weld material at EOL. ASME Code Section XI, Appendix K contains a methodology and criteria acceptable to the staff for satisfying the requirement in 10 CFR Part 50, Appendix G, paragraph IV.A.1.a to demonstrate that materials with Charpy USE values below 50 ft-lb provide margins of safety against fracture equivalent to those required by ASME Code Section XI, Appendix G. Therefore, by performing an analysis in accordance with ASME Code Section XI, Appendix K, the applicant stated that it satisfied the requirements in 10 CFR Part 50, Appendix G, paragraph IV.A.1.a for 53 EFPY.

4.2.2.2 Staff Evaluation

The applicant performed a plant-specific fracture mechanics evaluation, BAW-2467NP, July 2004, and demonstrated acceptable equivalent margins of safety against fracture. The extended EOL lower bounding J-R values and all acceptance ratios are summarized in LRA Table 4.2.2-1. From the table, it can be seen that the controlling weld is the Unit 1 RPV longitudinal weld SA-847. Since the values of the J-R ratios are greater than one, the acceptance criteria for the equivalent margins analysis were met.

To confirm that the applicant's analysis satisfied the criteria in ASME Code Section XI, Appendix K, the staff performed an independent analysis using the methodologies and models specified in RG 1.161, "Evaluation of Reactor Pressure Vessels With Charpy Upper-Shelf Energy Less Than 50 ft-lb," NUREG/CR-5729, "Multivariable Modeling of Pressure Vessel and Piping J-R Data," and ASME Code Section XI, Appendix K. Based on the analysis, the staff confirmed that the PBNP reactor vessel would have margins of safety against fracture equivalent to those required by ASME Code Section XI, Appendix G through the period of extended operation.

4.2.2.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of USE in LRA Section A15.4.1. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on USE and, is therefore, acceptable.

4.2.2.4 Conclusion

The staff reviewed the applicant's TLAA on USE, as summarized in LRA Section 4.2.2, and determined that the RV beltline materials at Units 1 and 2 will continue to comply with the staff's requirements in 10 CFR Part 50 throughout the period of extended operation. The staff concluded that the applicant's TLAA for USE complies with the staff's acceptance criterion for TLAAs in 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)(iii). The staff also concluded that the FSAR 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).

4.2.3 Reactor Vessel Pressure/Temperature Limits

Section 50.60 of 10 CFR, "Acceptance Criteria for Fracture Prevention Measures for Lightwater Nuclear Power Reactors for Normal Operation," and 10 CFR Part 50, Appendix G, "Fracture Toughness Requirements," set forth the staff's requirements and criteria for generating the P-T limits that are required for commercial U.S. light-water reactors.

4.2.3.1 Summary of Technical Information in the Application

Units 1 and 2 heatup and cooldown P-T limit curves were generated using adjusted reference temperature (ART) values that bound both units. The applicant concluded that the P-T limits for the units were TLAAs that needed to be assessed against the acceptance criteria of 10 CFR 54.21(c)(1)(ii). The P-T limit curves that apply for the current operating conditions are included in the Pressure and Temperature Limits Report (PTLR) for each unit. The PTLR was approved by the staff, and these requirements are incorporated into its technical specifications.

The PTLR will continue to be updated as required by either Appendices G or H of 10 CFR Part 50, or as operational needs dictate. The applicant stated that this will assure that operational limits remain valid for current and projected cumulative neutron fluence levels.

4.2.3.2 Staff Evaluation

Section 50.60 of 10 CFR provides acceptance criteria for fracture prevention measures for light water nuclear power reactors for normal operation, and it invokes the application of Appendices G or H of 10 CFR Part 50, as applicable. The PTLR will continue to be updated as required by either Appendices G or H of 10 Part CFR 50, or as operational needs dictate. The staff agrees that this will assure that operational limits remain valid for current and projected cumulative neutron fluence levels. Since the PTLR will continue to be updated as required by either Appendices G or H of 10 CFR Part 50, as applicable, additional analysis at this time is not required.

4.2.3.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of P-T limits in LRA Section A15.4.1. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on P-T limits and, is therefore, acceptable.

4.2.3.4 Conclusion

The staff reviewed the applicant's TLAA on P-T limits, as summarized in LRA Section 4.3.4, and determined that the RV beltline materials at Units 1 and 2, will continue to comply with the staff's requirements in 10 CFR 50.60 throughout the period of extended operation. The staff concluded that the applicant's TLAA for P-T limits complies with the staff's acceptance criterion for TLAAs in 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 FSAR 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).

4.3 <u>Metal Fatigue</u>

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 analyses is reviewed for the period of extended operation. NUREG-1801 identifies fatigue aging related effects that require evaluation as possible TLAAs pursuant to 10 CFR 54.21(c).

The applicant discussed the design requirements for components of the reactor coolant system. The reactor vessels were designed and fabricated in accordance with the requirements stated in the ASME Boiler and Pressure Vessel Code (ASME Code) Section III, 1965 Edition for Unit 1, and 1968 Edition through winter 1968 Addenda for Unit 2. The reactor coolant pressure boundary piping and components were designed and fabricated in accordance with the requirements of USAS B31.1, "Power Piping Code," 1955 Edition. Other safety-related piping and fittings were also designed and fabricated in accordance with the requirements of USAS B31.1, 1967 Edition.

4.3.1 Reactor Vessel Structural Integrity

4.3.1.1 Summary of Technical Information in the Application

In LRA Section 4.3.1, the applicant stated that the Unit 1 reactor vessel was designed to the ASME Code Section III, 1965 Edition and the Unit 2 reactor vessel was designed to ASME Code Section III, 1968 Edition with Addenda through winter 1968. The original reactor vessel Code Stress Reports included ASME Code Section III fatigue analyses of the reactor vessel components based on a set of nuclear steam supply system (NSSS) design basis transients and corresponding cycles, which are listed in FSAR Table 4.1-8.

The applicant stated that, in conjunction with the Steam Generator Replacement Project (SGRP) and the Power Uprate Project (PUP), the number of anticipated NSSS transients was projected for a 60-year operating period based on current plant operational practices and the number of NSSS transients actually experienced. With few exceptions, the anticipated number of transients for a 60-year operating period was far less than the original design number of transients for a 40-year operating period. However, the pressure test transients projected for a 60-year operating period exceeded the original design number of transients for a 40-year operating period. The NSSS design transient set was, therefore, revised to include an increased number of pressure test transients, sufficient for a 60-year operating period. In addition, the NSSS transient set was also revised to increase the number of steady-state random reactor coolant system (RCS) pressure and temperature fluctuations to ensure that adequate margin existed for a 60-year operating period. The revised set of NSSS design transients were used to perform the detailed engineering evaluations in support of the SGRP and the PUP. These evaluations were performed to assess the effects of the revised NSSS design transients on the stress intensity ranges and fatigue cumulative usage factors (CUFs) at locations identified in the reactor vessel stress reports. In the cases where the revised transients were not bounded by the original analyses, or the transients were not included in the original analyses, appropriate revised stress intensity ranges and CUFs were calculated. The evaluations demonstrated acceptable results in accordance with both the ASME Code Section III, 1965 Edition for the Unit 1 reactor vessel, and the ASME Code Section III, 1968 Edition with Addenda through winter 1968 for the Unit 2 reactor vessel. Otherwise, the design basis stress intensity ranges and CUFs reported in the original stress reports continued to be bounding.

The applicant stated that the reactor pressure vessel heads are scheduled for replacement in the 2005 refueling outages. The replacement heads will also include new control rod drive mechanisms (CRDMs). Material and design enhancements are being incorporated into the replacement heads to enhance the corrosion resistance of the head penetration assemblies. Other design enhancements are also being incorporated, including elimination of Alloy 600 materials, elimination of unnecessary spare head penetrations, elimination of unnecessary joints in the CRDM housings, and an improved penetration weld joint design. The replacement heads are being designed and manufactured to ASME Code Section III, 1998 Edition through

2000 Addenda. The design specification for the replacement RPV heads specifies the same design transient set that was used in the SGRP and the PUP but specifies a 40-year design-life. The 40-year design-life of the replacement heads is considered adequate to match the 60-year design-life of the other reactor vessel components.

4.3.1.2 Staff Evaluation

The applicant stated that the ASME Code Section III Class 1 fatigue analyses at various reactor vessel limiting locations were evaluated for extended operation, based on the Steam Generator Replacement Project and Power Uprate Project NSSS design transient set, projected to the end of the period of extended operation. These transient conditions and corresponding design cycles are shown in LRA Appendix A Table 4.1.8. A list of the 60-year fatigue CUFs for the reactor vessel components is also provided in LRA Table 4.3-2, where the highest calculated CUF is below 1.0. The applicant has, therefore, demonstrated that the fatigue CUFs at these locations meet the ASME Code Section III Class 1 design limiting value of 1.0 for the period of extended operation.

The staff's review of LRA Section 4.3.1 identified an area in which additional information was necessary to complete the review of the reactor vessel structural integrity evaluation. The applicant responded to the staff's RAI as discussed below.

RAI 4.3-1. In RAI 4.3.1, dated November 17, 2004, the staff requested the applicant to show that the limiting components of the PBNP reactor vessels evaluated for extended operation, correspond to the components listed in NUREG-1801 Table IV.A2, Volume 2, for PWR reactor vessels.

In its response, dated January 28, 2005, the applicant provided a table showing the components that were evaluated in the PBNP fatigue TLAAs. The locations shown in the table correspond to those in NUREG-1801, Volume 2. The staff found this response acceptable. The staff's concern described in RAI 4.3.1 is resolved.

Based on its review, the staff concluded that the applicant provided reasonable assurance that the reactor vessel fatigue TLAAs will remain valid to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.3.1.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of reactor vessel structural integrity in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on reactor vessel structural integrity and, is therefore, acceptable.

4.3.1.4 Conclusion

The staff reviewed the applicant's TLAA on reactor vessel structural integrity, as summarized in LRA Section 4.3.1, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for reactor vessel structural integrity complies with the staff's acceptance criterion for TLAAs in 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 FSAR supplement contains an appropriate summary description of the TLAA on reactor vessel structural integrity for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.2 Reactor Vessel Internals Structural Integrity

4.3.2.1 Summary of Technical Information In the Application

In LRA Section 4.3.2, the applicant stated that since the reactor vessel internals (RVI) were designed prior to the introduction of ASME Code Section III, Subsection NG, a plant-specific stress report on the RVI was not required for the original design. However, the RVI were analyzed according to Westinghouse criteria that were similar to the criteria described in Subsection NG. These analyses were used as the basis for the evaluations of critical RVI components for uprated power conditions for a 60-year operating period.

The RVI fatigue analyses were reevaluated for the same transients evaluated in the reactor vessel fatigue analyses. Structural evaluations were performed to demonstrate that the structural integrity of the RVI components were not adversely affected directly by the change in RCS conditions and transients and/or by secondary effects of the change on reactor thermal-hydraulic or structural performance. Westinghouse performed a review and an evaluation of the effects of the revised NSSS design transients and the full-power uprate conditions on key reactor internal components.

The applicant stated that the results of this evaluation concluded that the change in RCS thermal transients due to full uprated RCS conditions and a 60-year operating period does not significantly affect the fatigue CUFs. The CUFs of all RVI components analyzed for fatigue, using methods similar to those of Subsection NG, were also determined to be within the allowable limit of 1.0 for a 60-year operating period.

4.3.2.2 Staff Evaluation

The staff's review of LRA Section 4.3.2 identified areas in which additional information was necessary to complete the review of the RVI structural integrity evaluation. The applicant responded to the staff's RAIs as discussed below.

<u>RAI 4.3.2-1</u>. In RAI 4.3.2-1, dated November, 17, 2004, the staff requested the applicant to show that the limiting components of the RVI that were evaluated for extended operation correspond to the components listed in NUREG-1801 Table IV.B2, Volume 2, for PWR reactor vessel internals.

In its response, dated January 28, 2005, the applicant stated that the RVI were designed and manufactured prior to the availability of ASME Code Section III, Subsection NG, "Core Support Structures." Fatigue evaluations were, therefore, neither required nor performed for all components listed in Table IV.B2. However, the applicant indicated that the major RVI components were evaluated for fatigue, based on the intent of ASME Code Section III, Subsection NB. The applicant provided a table listing these major components (but not minor components such as hold-down springs, bolts, fuel alignment pins and baffles, and former plates) that were evaluated for fatigue.

On the basis of the above discussion, the staff found this response acceptable. The components that were evaluated for fatigue correspond to those shown in Table IV.B2 in NUREG-1801, Volume 2. The staff also found acceptable the justification for those components for which fatigue analyses were not performed. The staff's concern described in RAI 4.3.2-1 is resolved.

RAI 4.3.2-2. In RAI 4.3.2-2, dated November 17, 2004, the staff requested the applicant to provide the 60-year design-basis CUFs for the key RVI listed on LRA page 4-41.

In its response, dated January 28, 2005, the applicant provided a table listing these components and the corresponding CUFs, with the highest value being below 1.0. The fatigue CUFs were shown to be below the ASME Code Section III Class 1 fatigue limit of 1.0. The staff found this response acceptable.

On the basis of its review of LRA Section 4.3.2 and the RAI responses, the staff agreed with the applicant that the fatigue TLAAs of the RVI, based on power uprated transients and operating conditions, will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii). The staff's concern described in RAI 4.3.2-2 is resolved.

4.3.2.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of the RVI structural integrity in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on RVI structural integrity and, is therefore, acceptable.

4.3.2.4 Conclusion

The staff reviewed the applicant's TLAA on RVI structural integrity, as summarized in LRA Section 4.3.2, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for RVI structural integrity complies with the staff's acceptance criterion for TLAAs in 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 FSAR supplement contains an appropriate summary description of the TLAA on RVI structural integrity for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.3 Control Rod Drive Mechanism Structural Integrity

4.3.3.1 Summary of Technical Information in the Application

In LRA Section 4.3.3, the applicant stated that both units have full-length (F/L) control rod drive mechanisms (CRDMs). Unit 2 also has part-length (P/L) CRDMs. The F/L and P/L CRDMs were designed, constructed, and analyzed to the requirements of their original equipment specifications and ASME Code Section III. Generic ASME Code stress analyses were performed, subject to the licensing basis design transient sets that were specified in the original equipment specifications.

The applicant stated that the structural integrity of the F/L and P/L CRDMs was evaluated for uprated power conditions and a 60-year operating period, using the 60-year NSSS design parameters and the NSSS revised design transients. The fatigue analysis for the P/L CRDMs was determined to be bounded by the fatigue analysis for the F/L CRDMs. The revised set of NSSS design transients was compared to the transients used in the F/L CRDM equipment specification and the associated generic code stress analysis. The equipment specification or the generic code stress analysis values were determined to bound the revised NSSS values except for the large step-load decrease, loss of load, loss of flow, and reactor trip transients. The revised power uprate NSSS transient set also required consideration of feedwater cycling, boron concentration equalization, loss of power, inadvertent actuation of auxiliary spray, steam line break, and turbine roll tests transients, because they were not defined in the original equipment specification for the CRDMs. The transients that were not bounded, the "new" transients, and the additional hydrostatic test pressure transients were evaluated for their impact on fatigue. Based on these evaluations, and the previous generic code stress analyses, the applicant concluded that the design of the P/L and F/L CRDMs meets the applicable ASME Code requirements at uprated NSSS power conditions for up to 60 years of operation.

The applicant also stated that the CRDMs are scheduled for replacement in the 2005 refueling outages and are currently being manufactured. Material and design enhancements are being incorporated into the replacement CRDMs to enhance the corrosion resistance of the CRDM assemblies. Some of the enhancements include elimination of Alloy 600 materials, elimination of unnecessary spare head penetrations, elimination of unnecessary joints in the CRDM housings, and an improved penetration weld joint design. The replacement CRDMs are being designed and manufactured to ASME Code Section III, 1998 Edition through 2000 Addenda. The design specification for the replacement CRDMs specify the same design transient set that was used in the PUP but specified only a 40-year design-life. The applicant stated that this design-life is considered adequate for both original and replacement components to reach the end of the period of extended operation.

4.3.3.2 Staff Evaluation

The applicant stated that the impact of the power uprate NSSS transients on the fatigue calculations in the generic code stress analysis associated with the Westinghouse Equipment Specification for the CRDMs was evaluated and found to be acceptable. The applicant also stated that the CRDMs are scheduled for replacement during the 2005 refueling outages. The Westinghouse design specification for the replacement CRDMs specifies the design transient set used in the Steam Generator Replacement and the Power Uprate projects. The replacement CRDMs are being designed to the ASME Code Section III, 1998 Edition through 2000 Addenda, with a 40-year design life. The applicant stated that a 40-year design life is considered adequate to reach the end of the period of extended operation. The staff agreed with the specified 40-year design life for the replacement CRDMs, since these will be installed well past half of the current life of the two units.

The staff's review of LRA Section 4.3.3 identified an area in which additional information was necessary to complete the review of the CRDM structural integrity evaluation. The applicant responded to the staff's RAI as discussed below.

RAI 4.3-3. In RAI 4.3-3, dated November 17, 2004, the staff requested the applicant to provide a comparison of the CLB set of transient conditions and design cycles, and the revised set of full power uprate design transients.

In its response, dated January 28, 2005, the applicant referred to the two versions of LRA Table 4.1.8, "Thermal and Loading Cycles," shown on pages A-4 and A-5 in Appendix A "FSAR Supplement." The staff found the response acceptable since the comparison of the two tables shows a larger number of power uprate design transients and design cycles that are being used in the replacement CRDM fatigue TLAAs.

On the basis of the above discussion, the staff agreed with the applicant's overall conclusion that the fatigue analyses of the PBNP CRDMs will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii). The staff's concern described in RAI 4.3-3 is resolved.

4.3.3.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of CRDM structural integrity in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on CRDM structural integrity and, is therefore, acceptable.

4.3.3.4 Conclusion

The staff reviewed the applicant's TLAA on control rod drive mechanism structural integrity, as summarized in LRA Section 4.3.3, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for CRDM structural integrity complies with the staff's acceptance criterion for TLAAs in 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 FSAR supplement contains an appropriate summary description of the TLAA on CRDM structural integrity for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.4 Steam Generator Structural Integrity

4.3.4.1 Summary of Technical Information in the Application

In LRA Section 4.3.4, the applicant stated that PBNP replaced the steam generators (SGs) in each unit. The Unit 1 SGs were replaced in 1984, and the Unit 2 SGs were replaced in 1996. The projected number of SG design transients for a 60-year operating period were determined to be less than the original design value for a 40-year operating period, with the exception of hydrostatic pressure tests. The design transient set was revised to increase the number of hydrostatic pressure test transients for the fatigue analysis performed to cover a 60-year operating period. Both unit's SGs were designed in accordance with the requirements of the ASME Code Section III. The original fatigue calculations were reanalyzed for the Units 1 and 2 SGs at specified full uprated conditions and increased pressure test load cycles adequate for a 60-year operating period. The structural evaluation concluded that the CUFs of all SG components analyzed for fatigue are within the ASME Code Section III allowable limit of 1.0 for a 60-year operating period, with the exception of the Unit 1 inspection port bolts. The structural evaluation also determined a replacement interval of 12 years for these bolts. The Periodic Surveillance and Preventive Maintenance Program, described in LRA Section B2.1.15, will manage the Unit 1 SG inspection port bolt replacement. This bolting replacement program will remain in place for the period of extended operation.

4.3.4.2 Staff Evaluation

The applicant stated that the SGs were replaced in Unit 1 in 1984 and in Unit 2 in 1996. For license renewal, the fatigue TLAAs were reanalyzed at full power uprate transient conditions, and the CUFs were determined to meet the ASME Code Section III Class 1 fatigue limit of 1.0.

The staff's review of LRA Section 4.3.4 identified areas in which additional information was necessary to complete the review of the SG structural integrity evaluation. The applicant responded to the staff's RAIs as discussed below.

RAI 4.3.4-1. In RAI 4.3.4-1, dated November 17, 2004, the staff requested the applicant to confirm that the limiting locations on the PBNP Westinghouse Units 1 and 2 SGs evaluated for extended operation correspond to the components listed in NUREG-1801, Volume 2 Table IV.D1 for PWR SGs.

In its response, dated January 28, 2005, the applicant provided a table verifying that the applicable locations specified in NUREG-1801, Volume 2, were evaluated in the PBNP replacement SG fatigue analyses, except for two components, which are not found in the PBNP SGs. The staff found the applicant's response acceptable because the components that were evaluated for fatigue correspond to the components listed in NUREG-1801 Table IV.D1.

RAI 4.3.4-2. In RAI 4.3.4-2, dated November 17, 2004, the staff requested the applicant to provide clarification that the transient conditions and design cycles applicable to verify the replacement SG fatigue TLAAs were those stated in LRA Appendix A Table 4.1.8.

In its response, dated January 28, 2005, the applicant confirmed that the revised set of full power uprate transient conditions and design cycles shown in the revised LRA Appendix A Table 4.1.8, "Thermal and Loading Cycles," were used in the fatigue analyses of the Units 1 and 2 SGs, to show conformance with the ASME Code Section III Class 1 fatigue limit of 1.0 to the end of the period of extended operation.

RAI 4.3.4-3. In RAI 4.3.4-3, dated November 17, 2004, the staff requested the applicant to provide a list of the key Units 1 and 2 SG components and the corresponding 60-year CUFs.

In its response, dated January 28, 2005, the applicant provided a table which included the 14 key components for both SGs. The highest CUF for the Unit 1 SG was listed as 4.65 for the bolts of the secondary inspection ports. Since this value exceeds the ASME Code Section III Class 1 fatigue limit of 1.0, the applicant stated that these are managed by replacement on a periodic basis. For the other components of the Unit 1 SG, the highest CUF was below 1.0. For the Unit 2 SG, of a different Westinghouse design, the highest CUF was listed as also below 1.0.

The staff found these responses acceptable. It demonstrates the adequacy of the Units 1 and 2 SG fatigue TLAAs, and the commitment for periodic replacement under the Periodic Surveillance and Preventive Maintenance Program of the secondary inspection port bolts, where the fatigue TLAA does not meet the ASME Code Section III Class 1 fatigue limit of 1.0.

On the basis of the above discussion and its review, the staff agreed with the applicant's conclusion that the fatigue analyses of the SGs will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii) and (iii). The staff's concerns described in RAIs 4.3.4-1, 4.3.4-2, and 4.3.4-3 are resolved.

4.3.4.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of SG structural integrity in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on SG structural integrity and, is therefore, acceptable.

4.3.4.4 Conclusion

The staff reviewed the applicant's TLAA on SG structural integrity, as summarized in LRA Section 4.3.4, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for SG structural integrity complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(ii) and (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 FSAR supplement contains an appropriate summary description of the TLAA on SG structural integrity for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.5 Pressurizer Structural Integrity

4.3.5.1 Summary of Technical Information in the Application

In LRA Section 4.3.5, the applicant stated that, based on operating experience and a review of existing analyses, the Westinghouse Report WCAP-14574-A identified the shell, spray nozzle, manway bolts, lower head, heater wells, surge nozzle, and support skirt and flange as significant locations with fatigue potential for the period of extended operation.

The applicant stated that the pressurizers were designed in accordance with the requirements of ASME Code Section III Class 1 vessels. Fatigue usage factors for critical locations in the pressurizers were initially evaluated using design transients that were specified early in the plant design process.

The projected number of design transients for a 60-year operating period are less than the original design value for a 40-year operating period, with the exception of hydrostatic pressure tests. The pressurizer fatigue calculations were reanalyzed for the uprated power conditions with an increased number of hydrostatic pressure test-load cycles, adequate for a 60-year operating period. The applicant stated that the plant-specific fatigue analysis results showed that the surge nozzle, spray nozzle, and upper head and shell have the highest fatigue CUF, but do not exceed the ASME Code Section III allowable limit of 1.0.

The applicant stated that thermal fatigue damage to the pressurizer lower head region was being experienced on an industry-wide basis in excess of the original design allowable limit, due to apparent insurge/outsurge transients in the pressurizer. The original design analysis assumed that during an insurge transient, the cooler water from the hot leg entering the hotter pressurizer would mix in the bottom head of the pressurizer. This, however, has not been the case, and additional fatigue usage has resulted for the pressurizer components in the lower head region. The Westinghouse Owners Group (WOG) commissioned a generic evaluation of the effects of this unanalyzed event. As a result of this evaluation, the WOG tested and recommended modified operating procedures (MOP) for use in all plants to minimize or eliminate insurge/outsurge cycling. The WOG also demonstrated acceptable structural integrity of the pressurizers for the CLB design-life of the plant based on the MOP, and recommended plant-specific structural integrity evaluations to close the issue.

The applicant stated that PBNP implemented the recommended MOP to minimize the possibility of pressurizer insurge/outsurge events. In addition, a plant-specific insurge/outsurge fatigue analysis was performed to demonstrate adequate structural integrity for a projected 60-year operational period. The following locations were selected for analysis:

- pressurizer surge nozzle
- heater penetration well
- lower instrument nozzle

These locations were determined to represent the bounding fatigue locations in the lower head region. The pressurizer surge nozzle is subjected to thermal shock in combination with thermal expansion piping loads, thermal stratification piping loads in the horizontal portion of the surge line, and pressure. The pressurizer heater tube and instrument penetrations are subjected to thermal shock and pressure. The Electric Power Research Institute (EPRI) FatiguePro software program, part of the Fatigue Monitoring Program described in LRA Section B3.2, was customized to monitor fatigue-critical locations in the pressurizer's lower head at PBNP. An analysis was performed based on available real plant data to determine the incremental fatigue usage factor for known plant transients, including the effects of insurge/outsurge. ASME Code Section III Class 1 CUFs for the operating life of the plant were computed based on the results of real plant data, and expected future usage was computed using projections of expected plant cycles through the period of extended operation.

The technical approach used by the applicant is based on determining flow rates and heat transfer rates from the incoming fluid to calculate the temperature transients in the lower head components by using the FatiguePro program. The applicant stated that this approach has been verified to be conservative, based on thermocouple data from another plant, as well as plant-specific comparisons between the FatiguePro calculated water temperature and the surge line temperature instrument reading in the region of the surge nozzle. The temperatures at the nozzle and lower head are calculated in FatiguePro completely independently from the surge line temperature instrument. As part of FatiguePro, stress histories, using finite element models of the pressurizer surge nozzle and hot leg RCS surge nozzle (including thermal sleeves), were computed based on the calculated fluid temperatures histories. The stress histories were used to compute fatigue usage in FatiguePro.

The applicant stated that real plant data from various heatup/cooldown cycles since 1994 were analyzed to compute incremental fatigue usage for a heatup/cooldown cycle. The location with the highest fatigue usage in the pressurizer bottom head was determined to be at a heater penetration weld. However, the applicant stated that for this location, the primary stress transient is not due to insurge and outsurge, but rather due to the general thermal expansion stress that arises from the global heatup and cooldown of the pressurizer. This location is a stainless steel weld to the tube and clad, very close to the low-alloy steel pressurizer shell. A high steady-state dissimilar-metal thermal expansion stress is established during the heatup and is relaxed during the cooldown. It is of a magnitude that overwhelms the small stress additions coming from insurges and outsurges of fluid.

The applicant stated that historical data from actual plant heatup and cooldown cycles from startup to 1994 was reviewed to more accurately account for early plant operation. Using this data, and assuming projected plant heatup and cooldown cycles, the expected CUF for the limiting (heater penetration) location was determined as significantly less than 1.0. The analysis demonstrated acceptable structural integrity for these pressurizer locations for a 60-year projected life of the plant. The projected combined fatigue usage factors (including insurge/outsurge) for the three bounding locations are shown in LRA Table 4.3.5-1 "Pressurizer Lower Head Fatigue Results Including Insurge/Outsurge." The most limiting Units 1 and 2 CUF was determined as 0.057 for a heater penetration. The applicant also stated that, for confirmatory purposes, the Fatigue Monitoring Program will monitor fatigue usage at the fatigue-sensitive locations during the period of extended operation.

4.3.5.2 Staff Evaluation

The applicant stated that, based on operating experience and a review of existing analyses, the Westinghouse Report WCAP-14574-A identified the shell, spray nozzle, manway bolts, lower head, heater wells, surge nozzle, and support skirt and flange as potential fatigue significant locations for the period of extended operations.

The staff's review of LRA Section 4.3.5 identified areas in which additional information was necessary to complete the review of the pressurizer structural integrity evaluation. The applicant responded to the staff's RAIs as discussed below.

RAI 4.3.5-1. In RAI 4.3.5-1, dated November 17, 2004, the staff requested the applicant to confirm that the limiting components on the pressurizers evaluated for extended operation correspond to the components listed in NUREG-1801, Volume 2, Table IV.C2.5 for PWR pressurizers. In its response, dated January 28, 2005, the applicant provided a table confirming that the applicable components specified in NUREG-1801, Volume 2, were evaluated in the PBNP pressurizer fatigue analyses, except for one component not within the scope of license renewal and three components not found in the PBNP pressurizers.

The staff found this response acceptable. The components that were evaluated for fatigue TLAAs correspond to those shown in NUREG-1801, Volume 2, Table IV.C2.5. The staff also found acceptable the justification for those components for which a fatigue analysis was not performed. These components are either outside the scope of license renewal or not found in the PBNP pressurizers. The staff's concern described in RAI 4.3.5-1 is resolved.

RAI 4.3.5-2. In RAI 4.3.5-2, dated November 17, 2004, the staff requested the applicant to provide clarification that the transient conditions and design cycles applicable to the pressurizer fatigue TLAAs were those stated in LRA Appendix A Table 4.1.8. In its response, dated January 28, 2005, the applicant confirmed that the revised set of full power uprate transient conditions and design cycles shown in the revised LRA Appendix A Table 4.1.8, "Thermal and Loading Cycles," were used in the fatigue analyses of the PBNP pressurizers to show conformance with the ASME Code Section III Class 1 fatigue limit of 1.0 to the end of the period of extended operation.

The staff found this response acceptable; it conforms with general industry practice for performing metal fatigue analyses. The staff's concern described in 4.3.5-2 is resolved.

RAI 4.3.5-3. In RAI 4.3.5-3, dated November 17, 2004, the staff requested the applicant to clarify whether the plant-specific insurge/outsurge fatigue analyses are based on applicable insurge/outsurge transients in combination with the revised transients listed in LRA Appendix A Table 4.1.8. In its response, dated January 28, 2005, the applicant indicated that only heatup and cooldown transients, which are listed in the table, were significant in the plant-specific fatigue analysis of the pressurizer lower head and surge line components subjected to insurge/outsurge transients. The contribution of the other transients to the fatigue CUFs was found to be negligible.

The applicant stated that actual insurge/outsurge transients experienced by the pressurizer lower head and surge line components during plant heatup and cooldown were obtained from real time plant data using the EPRI FatiguePro fatigue monitoring software installed in both units. The software monitored the hot leg surge nozzle, the pressurizer surge nozzle, a pressurizer heater penetration weld, and a water temperature instrument nozzle. The heater penetration weld was determined to be the bounding location for fatigue usage. The fatigue CUF was estimated based on the number of operational cycles projected from the present to the end of the period of extended operation, and the number of cycles estimated to have been experienced from the start of plant operation until the beginning of fatigue monitoring with the Fatigue Monitoring Program. The fatigue usage calculations were also adjusted for the maximum environmental fatigue effect by multiplying by the maximum environmental effect factor of 15.35. The resulting environmental CUFs were determined to be less than the ASME Code Section III Class 1 fatigue limit of 1.0, and are shown in LRA Table 4.3.10.2.

The staff found this response acceptable; it conforms with general industry practice for performing metal fatigue analyses. The staff's concern described in RAI 4.3.5-3 is resolved.

RAI 4.3.5-4. In RAI 4.3.5-4, dated November 17, 2004, the staff requested the applicant to provide a description of the "Modified Operating Procedures," referenced on page 4-45 of the LRA, that were used to minimize or eliminate insurge/outsurge cycling. In its response, dated January 28, 2005, the applicant stated that PBNP follows a "water solid" heatup-cooldown method for both units. The modified operating procedures set a maximum allowable temperature differential limit between the RCS hot leg and the pressurizer liquid space. This ensures that the operation of the plant is within the temperature differential limit assumed in the surge line thermal stratification analysis.

The staff found this response acceptable; it conforms with standard industry practice. The staff's concern described in RAI 4.3.5-4 is resolved.

RAI 4.3.5-5. In RAI 4.3.5-5, dated November 17, 2004, the staff requested the applicant to list the key Units 1 and 2 pressurizer components that were evaluated for 60-year fatigue, and to provide the calculated CUFs for these components. In its response, dated January 28, 2005, the applicant provided the requested table, listing 12 key components that were evaluated for fatigue, with the corresponding CUFs to the end of the period of extended operation. The highest CUF reported was at the spray nozzle, and its magnitude was below the ASME Code Section III Class 1 fatigue limit of 1.0.

Based on the discussion above, its review and the RAI response, the staff found this TLAA acceptable. The reported CUFs are below the required ASME Code limit, and it provides a reasonable demonstration that the fatigue TLAAs for the pressurizer, including insurge/outsurge transients, will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.3.5.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of pressurizer structural integrity in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on pressurizer structural integrity and, is therefore, acceptable.

4.3.5.4 Conclusion

The staff reviewed the applicant's TLAA on pressurizer structural integrity, as summarized in LRA Section 4.3.5, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for pressurizer structural integrity complies with the staff's acceptance criterion for TLAAs in 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 FSAR supplement contains an appropriate summary description of the TLAA on pressurizer structural integrity for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.6 Reactor Coolant Pump Structural Integrity

4.3.6.1 Summary of Technical Information in the Application

In LRA Section 4.3.6, the applicant stated that the reactor coolant pumps (RCPs) were designed and manufactured prior to the inclusion of pumps into the scope of ASME Code. Therefore, the RCPs do not have a classical ASME Code Class 1 fatigue analysis. Although the RCPs were designed and manufactured prior to the inclusion of pumps into the scope of ASME Code, they were designed and manufactured to the intent of ASME Code Section III, 1965 Edition. The areas of the RCP that form the reactor coolant pressure boundary would, therefore, be subject to an ASME Code-type stress analysis. These components are the casing, the main flange, the main flange bolts, and the thermal barrier flange.

The main flange bolts, the main flange, and the casing were analyzed to ASME Code rules, including a fatigue evaluation, in the Westinghouse Model 93 generic stress reports. The thermal barrier, the seal housing, and the seal housing bolts were included in the Westinghouse Model 93 generic stress analysis, which evaluated steady-state operating conditions and the anticipated transient without trip (ATWT) event, an emergency condition, to ASME Code rules. For PBNP, no transients were specified for the auxiliary nozzles for injection and cooling water, and no analysis of these areas is contained in the generic stress reports.

The applicant stated that the main flange bolts were analyzed for fatigue and found to have a usage factor of 0.29. The fatigue-waiver methodology was not used for these bolts. This usage factor was calculated on the basis of 200 startup/shutdown cycles. This analysis determined that the transient conditions other than startup/shutdown produced stresses so low as not to contribute to the fatigue usage of the main flange bolts.

A fatigue analysis was performed for the main flange. A usage factor of 0.025 was calculated on the basis of 200 startup/shutdown cycles. The analysis determined that the transient conditions other than startup/shutdown produced stresses so low as not to contribute to the fatigue usage of the main flange. This is because the thermal barrier serves to isolate the main flange from temperature transients smaller than startup and shutdown. The pump casing was analyzed, and the applicant concluded that the fatigue usage factor for the casing is zero.

The applicant stated that the SG replacement and power uprate evaluations evaluated the adequacy of the RCPs for uprated power conditions for a 60-year operating period. New NSSS transient data were created for the Power Uprate Project. The revised transient set was reviewed against the original RCP design transients. The applicant found that generally, the revised transient sets were bounded by the original RCP design transient sets. However, the revised transient sets included some transients that were not included in the original RCP design transients. These additional transients were evaluated in the justification of the adequacy of the RCP for uprated conditions for a 60-year operating period. The revised cycle count for a 40-year operating period was determined to also bound a 60-year operating period.

For the transients that were not bounded by the original design specification transients, the ASME fatigue-waiver criteria were used to the justify the adequacy of the RCPs for the uprated power conditions for a 60-year operating period. The temperature difference for a significant temperature fluctuation per paragraph N–415.1(d), and the pressure difference for a significant pressure fluctuation per paragraph N–415.1(b), were calculated by the applicant. These were then used to demonstrate that the new or revised transients associated with the Replacement Steam Generator Project and Power Uprate Project were not significant per the ASME Code fatigue-waiver criteria and, therefore, do not contribute to the CUF for the RCP components.

The applicant stated that the referenced evaluations confirmed that the design of the Model 93 RCP met the applicable ASME Code requirements for structural integrity at the revised RCS conditions associated with the uprated core power for up to a 60-year life. The analyses associated with verifying the structural integrity of the RCPs were projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.3.6.2 Staff Evaluation

As described above, the applicant designed the RCPs to the intent of ASME Code Section III Class 1. These requirements contain explicit criteria for the fatigue analysis of components, and the applicant identified the fatigue analyses of the RCP pressure boundary as TLAAs. The staff reviewed the applicant's evaluation of the components for compliance with the provisions of 10 CFR 54.21(c)(1).

The specific design criterion for fatigue analysis of RCS components involves calculating the CUF. The fatigue damage in the component caused by each thermal or pressure transient depends on the magnitude of the stresses caused by the transient. The CUF sums the fatigue damage resulting from each transient with the design criterion requiring that the CUF not exceed 1.0.

The applicant classified the RCP, main flange bolts, and main flange as pressure-retaining components subject to fatigue. In its technical information section, the applicant indicated that fatigue usage factors were calculated for these three components and that plant transients, including those not bounded by the original design transients, were not significant, pursuant to the ASME Code fatigue waiver criteria, and do not contribute to the CUF for the RCP components. The effects of fatigue on these system components are addressed under the Fatigue Monitoring Program, which is evaluated by the staff in SER Section 3.0.3.2.22, and is acceptable, as previously discussed.

4.3.6.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of RCP structural integrity in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on RCP structural integrity and, is therefore, acceptable.

4.3.6.4 Conclusion

The staff reviewed the applicant's TLAA on RCP structural integrity, as summarized in LRA Section 4.3.6, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for RCP structural integrity complies with the staff's acceptance criterion for TLAAs in 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 FSAR supplement contains an appropriate summary description of the TLAA on RCP structural integrity for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.7 Pressurizer Surge Line Structural Integrity

4.3.7.1 Summary of Technical Information in the Application

In LRA 4.3.7, the applicant stated that detailed fatigue analyses of the pressurizer surge lines were performed in response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." The analyses were performed in accordance with the requirements of ASME Code Section III. The methodology and results are presented in WCAP-13509, "Structural Evaluation of the Point Beach Units 1 and 2 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification."

The applicant stated that the Westinghouse analysis initially developed surge line transients from a number of sources. The transients were developed following the same general approach originally established for the Westinghouse Owners Group. The transients from the Westinghouse systems standard design transient set were refined through the use of PBNP-specific and similar-plant surge line monitoring results, operational procedures, and historical plant operational information. The transient refinements included the potential thermal effects of thermal stratification and striping. The transient information was used as input to a structural and stress analysis of the surge lines for the two units. The results of the analysis, following minor hanger and pipe whip restraint modifications, showed that the ASME Code stress limits and CUF requirements were acceptable for the remainder of the original license period.

The applicant stated that the PBNP-specific surge line fatigue analysis was re-evaluated considering the operational conditions associated with power uprate and a 60-year operating period. The transient sets were reviewed for the new conditions. The majority of the transients defined for original power levels for 40 years were found to be bounding for uprated conditions for 60 years. Some of the feedwater transients required minor revisions due to a change in feedwater temperatures associated with the proposed power uprate. The impact of the changes in the revised RCS conditions, thermal design transients, and the 60-year life were factored into determining the ASME Code stress levels and allowables for the surge line.

The results of the evaluation for the pressurizer surge line stratification showed that the power uprate conditions changed the fatigue usage factors at the location of the highest usage factor by a negligible amount. The calculated change in the loadings on the pressurizer nozzle due to stratification for the power uprate conditions was not considered significant. The results of the original evaluation for the surge line, WCAP-13509, remain unchanged for the 60-year operating period.

The analysis associated with verifying the structural integrity of the pressurizer surge line piping has been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii). For license renewal, continuation of the Fatigue Monitoring Program into the period of extended operation will assure that the design cycle limits are not exceeded. The Fatigue Monitoring Program is considered a confirmatory program and is described in LRA Section B3.2.

4.3.7.2 Staff Evaluation

The fatigue TLAAs were performed by Westinghouse in response to the criteria of NRC Inspection & Enforcement (I&E) Bulletin 88-11 to evaluate the structural integrity of the surge lines due to thermal stratification transients.

The staff's review of LRA Section 4.3.7 identified an area in which additional information was necessary to complete the review of the pressurizer surge line structural integrity evaluation. The applicant responded to the staff's RAI as discussed below.

RAI 4.3-7. In RAI 4.3-7, dated November 17, 2004, the staff requested the applicant to provide a comparison of the CLB set of transient conditions and design cycles and the set of full power uprate transients that were used to evaluate the pressurizer surge line fatigue TLAAs under power uprate conditions and to show that the fatigue TLAAs will remain valid for the period of extended operation.

In its response, dated January 28, 2005, the applicant stated that Westinghouse had evaluated the impact of the changes in the RCS operating conditions, thermal design transients, and projected 60-year life on the surge line thermal stratification analyses. The evaluation showed that the effect of the power uprate operating conditions on the surge line fatigue TLAAs changed the CUF at the location of the limiting fatigue CUF by a negligible amount. The applicant concluded that the results presented in the Westinghouse responses to I&E Bulletin 88-11 remain essentially unchanged.

On this basis, the staff concluded that the fatigue TLAAs associated with power uprated operating conditions and thermal stratification transient conditions for the pressurizer surge lines conform with current industry license renewal practices and will remain valid to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii). The staff's concern described in RAI 4.3-7 is resolved.

4.3.7.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of pressurizer surge line structural integrity in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on pressurizer surge line structural integrity and, is therefore, acceptable.

4.3.7.4 Conclusion

The staff reviewed the applicant's TLAA on pressurizer surge line structural integrity, as summarized in LRA Section 4.3.7, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for pressurizer surge line structural integrity complies with the staff's acceptance criterion for TLAAs in 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 FSAR supplement contains an appropriate summary description of the TLAA on pressurizer surge line structural integrity for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.8 Pressurizer Spray Header Piping Structural Integrity

4.3.8.1 Summary of Technical Information in the Application

In LRA Section 4.3.8, the applicant stated that the piping connections to the RCS were evaluated in response to NRC Bulletin 88-08 (including Supplements 1 through 3) "Thermal Stresses in Piping Connected to Reactor Coolant Systems." Two unisolable piping connections were identified that have the potential to be subjected to thermal stratification or temperature oscillations. These lines are the auxiliary charging connection and the auxiliary spray connection. The applicant inspected these lines with surface and volumetric inspection techniques to identify the presence of service-related degradation. No service-related degradation was discovered by the applicant.

These lines were also subject to temperature monitoring to identify and quantify thermal stratification. No thermal stratification was noted on the auxiliary charging lines. Thermal stratification was noted on one of the auxiliary spray lines, where it ties into the spray header. To evaluate the effect of thermal stratification on the pressurizer spray line header, including the auxiliary spray line connection, fatigue analyses were performed for each unit's applicable piping system. The analyses were based on actual piping surface temperature data obtained during a 153-day period (including one startup) of direct temperature monitoring on the Unit 2 piping. The Unit 2 data were considered applicable and bounding for both units since Unit 2 experienced more stratification, and the line configuration was similar in both units.

The applicant stated that the piping transient set was developed by expanding the measured piping thermal behavior to equate to a 40-year operating period. The analyses showed that the limiting CUFs in the subject piping were 0.66 for Unit 1 and 0.33 for Unit 2. Extrapolating the results of the original NRC Bulletin 88-08 analyses to a 60-year operating period resulted in CUFs of 0.99 for the Unit 1 piping system, and 0.60 for the Unit 2 piping system.

In view of the lack of margin with the Unit 1 piping system analysis result for the extended EOL, additional analysis investigations were pursued by the applicant. The original NRC Bulletin 88-08 analyses incorporated simplified analysis techniques and assumptions. The applicant concluded that it was not clear that the analysis was in fact conservative. Therefore, the NRC Bulletin 88-08 fatigue analyses were re-performed with refined analysis techniques and assumptions, using the original temperature monitoring data. The reanalysis resulted in a 60-year CUF of 0.277 for the limiting Unit 1 piping system location.

The applicant stated that the analyses verifying the structural integrity of the pressurizer auxiliary spray line and spray header, were projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii).

4.3.8.2 Staff Evaluation

The fatigue TLAAs were performed in response to the criteria of NRC I&E Bulletin 88-08 to evaluate the structural integrity of unisolable lines connected to the RCS, subject to thermal stratification transients resulting from leaking isolation valves.

The staff's review of LRA Section 4.3.8 identified an area in which additional information was necessary to complete the review of the pressurizer spray header piping structural integrity evaluation. The applicant responded to the staff's RAI as discussed below.

RAI 4.3-8. The applicant stated that the highest 40-year CUF for the pressurizer spray line headers in both units, including the auxiliary spray line connections, was calculated as 0.66. The projected highest CUF value for 60-year operation was, therefore, below 1.0. Although this value was below the ASME Code Section III Class 1 limit, the applicant determined that the original calculation may not have been conservative. In view of the small margin in the projected CUF value, the applicant therefore, calculated a 60-year CUF using refined fatigue analysis techniques and assumptions, and determined a CUF value of 0.277.

In RAI 4.3-8, dated November 17, 2004, the staff requested the applicant to provide a detailed description of the refined fatigue analysis techniques and assumptions used to determine the 60-year CUF.

In its response, dated January 28, 2005, the applicant stated that in the original response to NRC I&E Bulletin 88-08, the thermal stratification stresses were estimated using simplified hand calculations. These calculations contained estimates of global moments, and radial and axial stresses. A review of the assumptions made in these simplified calculations indicated that they may have been non-conservative. The correct thermal stratification stresses were therefore, calculated using a commercial finite-element analysis computer program which has the capability to calculate non-axisymmetric transient thermal and stress distributions in pipe walls, as well as global bending moments and stresses.

Input to this analysis consisted of thermal stratification data collected over a 153-day period from thermocouples installed on the auxiliary spray lines as part of the requirements of I&E Bulletin 88-08 to monitor the thermal stratification transients in these lines. These thermocouples recorded stratified thermal conditions resulting from a leaking auxiliary spray isolation valve. The applicant reviewed the thermocouple data in detail and extrapolated this data to a 60-year plant life, assuming that the same amount of valve leakage and thermal stratification continued to exist to the end of plant extended operation. The 60-year fatigue usage was computed at the limiting location of the auxiliary spray line using a method shown in ASME Code Section III, Subsection NC for Class 2 piping, based on thermal expansion and thermal stratification stress ranges.

The staff reviewed the methodology and procedures described in the applicant's response and found them acceptable; they conform with commonly accepted industry practice. The staff's concern described in RAI 4.3-8 is resolved.

The staff reviewed Section 4.3.8 and the applicant's response to the RAI and found it acceptable; it conforms with current industry license renewal practice. On this basis the staff concluded that the fatigue TLAAs associated with power uprated operating conditions and the thermal stratification transient conditions for the pressurizer spray header lines associated with I&E Bulletin 88-08, will remain valid to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.3.8.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of pressurizer spray header piping structural integrity in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on pressurizer spray header piping structural integrity and, is therefore, acceptable.

4.3.8.4 Conclusion

The staff reviewed the applicant's TLAA on pressurizer spray header piping structural integrity, as summarized in LRA Section 4.3.8, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for pressurizer spray header piping structural integrity complies with the staff's acceptance criterion for TLAAs in 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 FSAR supplement contains an appropriate summary description of the TLAA on pressurizer spray header piping structural integrity for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.9 USAS B31.1 Piping Structural Integrity

4.3.9.1 Summary of Technical Information in the Application

In LRA Section 4.3.9, the applicant stated that piping and associated pressure boundary components were originally designed to the requirements of USAS B31.1, "USA Standard Code for Pressure Piping." The B31.1 Code requirements assume a stress range reduction factor to provide conservatism in the piping design to account for the effects of thermal fatigue due to thermal cycling during operation. This reduction factor is 1.0, provided that the number of anticipated cycles is limited to 7000 equivalent full-temperature cycles. This represents a condition in which a piping system would have to be thermally cycled approximately once every three days over the extended plant life of 60 years.

Considering this limit, the applicant stated that a review of the piping and associated pressure boundary components included within the scope of license renewal was performed to identify those systems that operate at elevated temperature and to establish their cyclic operating practices. Under current plant operating practices, piping and associated pressure boundary components are occasionally subjected to cyclic operation. Typically, piping and associated pressure boundary components are subjected to continuous steady-state operation and operating temperatures, and only vary during plant heatup and cooldown, during plant transients, or during periodic testing. Therefore, the applicant stated that it is very unlikely for any piping system subject to thermal fatigue, that the actual number of thermal cycles would approach the assumed B31.1 limit of 7000 cycles during the period of extended operation except for the primary sampling system lines.

Establishing sample flow from the RCS results in thermal transients and cyclic stresses whenever the RCS is above ambient temperatures. The hot leg sample line receives the highest number of thermal cycles of all piping. An evaluation of the number of thermal cycles that the hot leg sample line would be expected to experience over a 60-year period of operation was performed. The applicant stated that its evaluation demonstrated that the hot leg sample line will not exceed 7000 thermal cycles over a 60-year operating period. Therefore, no piping and associated pressure boundary components are expected to exceed 7000 thermal cycles over a 60-year operating period, and will remain within the bounds of their original design code.

4.3.9.2 Staff Evaluation

This piping and associated pressure boundary components at PBNP were originally designed to the requirements of the USAS B31.1, 1967 Edition, "Power Piping Code," with the exception of the RCS piping and components which were designed to the requirements of the 1955 Edition. The USAS B31.1, 1967 Edition, Code requirements assume stress range reduction factors in the piping design to account for the effects of fatigue due to thermal cycling during plant operation. For anticipated thermal cycles equivalent to 7000 equivalent full-temperature cycles or less, the stress range reduction factor is 1.0. This represents a condition in which a piping system would have to be thermally cycled approximately once every 3 days over the extended plant life of 60 years.

The applicant reviewed the piping and associated pressure boundary components within the scope of license renewal to identify those systems that operate at elevated temperature and to establish their cyclic operating practices, considering the 7000-cycle limit. Based on this review, the applicant concluded that no piping and associated pressure boundary components are expected to exceed 7000 thermal cycles, including cycling occurring under full power uprate conditions, over a 60-year operating period and, will therefore, remain within the bounds of their original design code.

Based on current industry practice and experience and the applicant's compliance with the acceptance criteria in NUREG-1800, the staff agreed with the applicant's assessment that, for any PBNP piping system designed to USAS B31.1, 1967 Edition, with the exception of the RCS piping and components designed to the requirements of the 1955 Edition, it is highly unlikely that the 7000-cycle limit will be exceeded for the 60-year life of the plant.

On the basis of its review, the staff concluded that the fatigue analyses of the PBNP piping designed to the USAS B31.1 Power Piping Code were determined to remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.3.9.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of USAS B31.1 piping* structural integrity in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on USAS B31.1 piping structural integrity and, is therefore, acceptable.

4.3.9.4 Conclusion

The staff reviewed the applicant's TLAA on USAS B31.1 piping structural integrity, as summarized in LRA Section 4.3.9, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for USAS B31.1 piping structural integrity complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(i), 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 FSAR supplement contains an appropriate summary description of the TLAA on USAS B31.1 piping structural integrity for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.10 Environmental Effects on Fatigue

4.3.10.1 Summary of Technical Information in the Application

In the December 1999 closure of GSI-190, the staff concluded that environmental effects have a negligible impact on core damage frequency, and as such, no generic regulatory action was required. However, as part of the closure, the staff concluded that licensees who apply for license renewal should address the effects of reactor coolant environment on component fatigue life as part of their aging management programs. In LRA Section 4.3.10, the applicant addressed the potential effects of reactor water environments on RCS component fatigue life to determine if any aging management program actions are required during the period of extended operation.

In NUREG/CR-6260 "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," the Idaho National Engineering Laboratories (INEL) evaluated fatigue-sensitive component locations at plants designed by all four U.S. NSSS vendors. The applicant stated that the pressurized water reactor calculations, especially the early-vintage Westinghouse calculations, are directly relevant to PBNP. In addition, the transient cycles considered in the evaluation match or bound the PBNP design. The fatigue-sensitive component locations chosen in NUREG/CR-6260 for the early-vintage Westinghouse plant were:

- reactor vessel shell and lower head
- reactor vessel inlet and outlet nozzles
- pressurizer surge line (including the pressurizer and hot leg nozzles)
- reactor coolant system piping charging system nozzle
- reactor coolant system piping safety injection nozzle
- residual heat removal system class 1 piping

For the latter three component locations, INEL performed representative design-basis fatigue calculations, because early-vintage Westinghouse plants, including PBNP, utilized USAS B31.1 design methodology for the majority of the Class 1 piping. NUREG/CR-6260 calculated the fatigue usage factors for these locations using the interim environmental fatigue curves provided in NUREG/CR-5999.

For license renewal, the applicant stated that environmental fatigue calculations were performed for those component locations included in NUREG/CR-6260, using the F_{en} methodology contained in NUREG/CR-6583 for carbon/low-alloy steel material, and NUREG/CR-5704 for stainless steel material. The results are summarized below.

Reactor Pressure Vessel Locations. The applicant stated that the existing CUFs for the reactor vessel locations, calculated from fatigue analyses based on a full transient set at uprated conditions, were unaffected by environmental effects. The highest CUF was determined as 0.731 at the core support pad attachment to vessel shell location, which is lower than the ASME Code Section III limiting value of 1.0 and, therefore, the applicant concluded that it was acceptable.

Surge Line Locations. Since the PBNP pressurizer surge lines were designed and constructed to USAS B31.1, 1955 Edition, no specific fatigue analysis was performed for this piping. However, detailed structural and fatigue analyses were subsequently performed in response to NRC I&E Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." These evaluations were performed to the requirements of ASME Code Section III and were based on a 40-year design transient set, which also included the effects of thermal stratification. The summary results of these specific analyses were presented in Westinghouse WCAP-13509, "Structural Evaluation of the Point Beach Units 1 and 2 Pressurizer Surge Lines, Considering the Effects of Thermal Stratification."

The highest CUF of 0.99 was calculated at a welded attachment for a whip restraint on the outside surface of the middle section of the Unit 1 surge line. However, this surface of the pipe is not exposed to reactor coolant and consideration of environmental conditions, therefore, do not apply. The fatigue usage at this location was accumulated during the period when the piping support configuration allowed binding of the pipe within the restraint system. The restraint was modified to prevent future binding and, therefore, the applicant concluded that no further fatigue accumulation is expected to occur at this location.

The next highest CUF for Unit 1, and the highest CUF for Unit 2, occurred at the reducer below the pressurizer surge nozzle. The CUF is 0.7. An environmental fatigue multiplier of 15.35 for austenitic stainless steel was applied to the fatigue calculation result. The resulting environmental CUF for this location was calculated as 10.75. The environmental effects on fatigue were therefore, evaluated using actual monitored and projected fatigue data obtained with the EPRI FatiguePro software program. An analysis was performed and CUFs for the operating life of the plant were computed based on this data to determine the incremental CUF for known plant transients, including the effects of insurge/outsurge and environmental effects. The analysis showed that the environmental CUF was below 1.0 for a 60-year operating life.

The pressurizer surge line location subject to NUREG/CR-6260 analysis is the hot leg surge line nozzle. The evaluation at this location yielded an environmentally adjusted CUF of 0.588.

<u>USAS B31.1 Locations</u>. The applicant stated that, as with the older vintage Westinghouse plants evaluated in NUREG/CR-6260, detailed ASME Code fatigue usage calculations did not exist for the RHR tee, charging nozzle, and safety injection (accumulator) nozzle, because the design basis for the piping is USAS B31.1, which does not require specific fatigue analysis.

The design inputs for PBNP were compared to those summarized in NUREG/CR-6260 for these three components. The charging nozzle and safety injection nozzle were determined to be identical in terms of materials and geometry as those presented in NUREG/CR-6260. The RHR tee is identical in terms of material, but is larger than the RHR tee analyzed in NUREG/CR-6260.

PBNP-specific simplified ASME Code Section III fatigue analyses were performed on the subject locations to ensure that bounding fatigue information was used in the environmental effects on fatigue evaluation. For the RHR tee, where it ties into the accumulator injection line, the environmental fatigue CUF was calculated as 0.22, using a bounding environmental fatigue multiplier of 15.35 for austenitic stainless steel. For the safety injection (accumulator) nozzle, where the safety injection (accumulator) line ties into the RCS main loop piping, the resulting environmental CUF was calculated as 0.02, also based on a bounding environmental fatigue multiplier of 15.35 for austenitic stainless steel. For the CVCS normal charging nozzle, where the CVCS charging line ties into RCS main loop piping, the resulting environmental CUF was calculated as 0.83, based on an effective environmental fatigue multiplier of 6.99 calculated for this location.

<u>Pressurizer</u>. The applicant stated that, in addition to the NUREG/CR-6260 locations, the pressurizers were also evaluated for the effects of RCS environment on fatigue, including insurge/outsurge transients, in accordance with Applicant Action Item 3.3.1.1-1 of the pressurizer Westinghouse Generic Technical Report, WCAP-14574-A.

The CUFs of the pressurizers were recalculated for environmental effects on fatigue using the design transients and loads for the RSG/PUP. The calculation re-evaluated the CUFs at the following locations:

- spray nozzle
- surge nozzle
- junction of the upper head and shell
- safety and relief nozzle
- instrument nozzle
- heater well

The applicant applied the methods of Appendix B of EPRI Report TR-1003083, "Materials Reliability Program Guidelines for Addressing Fatigue Environmental Effects in a License Renewal Application (MRP-47)," October 2001, for performing the environmental effects evaluations of the CUFs of these pressurizer components. The calculated CUFs for these components are listed below:

• spray nozzle	3.2814	• safety and relief nozzle	0.1483
• surge nozzle	2.3252	• instrument nozzle	0.6293
• junction of the upper head and shell	0.7737	• heater well	0.2739

Since the evaluation, based on the design transient set, did not result in acceptable environmental CUFs for the surge and spray nozzles, the applicant reviewed the transients and transient pairs for specific contributions to the calculation of these CUFs. The review indicated that significant reductions in the CUFs are possible if adjustments are made to remove operational transients that are not experienced or practiced at PBNP. In addition, the EPRI FatiguePro software program was customized to monitor fatigue-critical locations in the pressurizer's spray nozzle and lower head components. Based on real plant data and projected plant transients and cycles, including the effects of insurge/outsurge, the applicant recalculated the environmental CUFs for the operating life of the plant, and demonstrated that the CUFs at the spray and surge nozzles were reduced to below 1.0.

The environmental fatigue evaluation of the pressurizer's lower head components, pressurizer spray nozzle, including insurge/outsurge, was also performed using the EPRI FatiguePro software program to demonstrate adequate structural integrity for a projected 60-year operational period. Environmental CUFs were conservatively determined by applying the maximum environmental fatigue correction factor of 15.35 at the affected component locations. On this basis, the applicant concluded that the results of the environmental fatigue evaluation coupled with the EPRI FatiguePro real data indicated that the pressurizer subcomponents have acceptable environmentally-adjusted CUF values, less than the allowable value of 1.0.

4.3.10.2 Staff Evaluation

Generic Safety Issue (GSI)-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of 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 (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 breaks as plants continue to operate. Thus, the staff concludes that, consistent with existing requirements in 10 CFR 54.21, licensees should address the effects of coolant environment on component fatigue life as aging management programs are formulated in support of license renewal.

The staff's review of LRA Section 4.3.10 identified areas in which additional information was necessary to complete the review of the environmental effects on fatigue evaluation. The applicant responded to the staff's RAIs as discussed below.

In LRA Section 4.3.10, the applicant evaluated the component locations listed in NUREG/CR-6260 that are applicable to an older-vintage Westinghouse plant for the effect of the environment on the fatigue life of the components. The applicant stated that 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 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. The fatigue analyses were based on the transient set under full uprated conditions and the period of extended operation. For those components that were designed to USAS B31.1, 1967 Edition, the applicant calculated the environmental CUFs based on a simplified ASME Code Section III fatigue analysis. The calculations showed that for the locations corresponding to those listed in NUREG/CR-6260, none of the environmental fatigue CUFs exceeded the ASME Code Section III Class 1 fatigue limit of 1.0 for the period of extended operation.

RAI 4.3.10-1. In RAI 4.3.10-1, dated November 17, 2004, the staff requested the applicant to provide a description of the simplified ASME Code Section III fatigue analysis used to calculate cumulative usage factors.

In its response, dated January 28, 2005, the applicant stated that the analysis of the charging nozzle was based on bounding thermal transients obtained from actual plant data using an application of the EPRI FatiguePro software and the projected number of occurrences. The bounding event was determined to be the loss of charging and loss of letdown event with delayed return to service. The fatigue usage was calculated for one occurrence and multiplied by the expected number of occurrences for 60-year operation. An F_{en} factor was then applied to the calculated fatigue usage to determine the environmental fatigue CUF. This CUF was determined to be below the ASME Code Section III Class 1 fatigue limit of 1.0. The safety injection nozzle and the RHR tee were analyzed using design transients and design cycles in a plant-specific ASME Code Section III Class 1 fatigue analysis of the safety injection system and the RHR system. The 60-year environmental fatigue CUFs were determined to be well below the ASME Code Section III Class 1 fatigue limit of 1.0.

The applicant also determined the environmental effects on the fatigue CUFs for key pressurizer components. The environmental fatigue CUFs at the spray nozzle and the surge nozzle were found to exceed the ASME Code Section III Class 1 fatigue limit of 1.0. The fatigue analyses of these components were revised based on an evaluation of the actual thermal transients experienced by these components, projected for 60-year operation. This evaluation eliminated operational design transients from the fatigue calculations that do not apply to the pressurizers. On this basis, the applicant showed that the environmental fatigue CUFs were reduced below the ASME Code Section III Class 1 fatigue limit of 1.0.

The staff reviewed this procedure and found it acceptable. It conforms with current industry practice and the NRC approach for calculating environmental effects on fatigue. The staff's concern described in RAI 4.3.10-1 is resolved.

RAI 4.3.10-2. The applicant's evaluation for environmental effects on fatigue was based on the environmental fatigue approach in EPRI MRP-47 methodology. The staff has not endorsed this approach. In RAI 4.3.10-2, dated November 17, 2004, the staff requested the applicant to provide the environmental fatigue CUFs based on the NRC methodology stated in NUREG-1800 Sections 4.3.2.2 and 4.3.3.2. These sections indicate that the environmental effects on fatigue may be determined based on NUREG/CR-6583 for carbon and low-alloy steels, and NUREG/CR-5704 for austenitic stainless steels. The staff methodology and the EPRI methodology are similar, except for a so-called "Z" factor, which acts to reduce the calculated EPRI-based F_{en} factors.

In its response, dated January 28, 2005, the applicant revised the environmental fatigue calculations with F_{en} factors based on the NUREG reports, and determined that the environmental 60-year CUF at the carbon/low-alloy steel junction of the upper head and shell would exceed the ASME Code Section III Class 1 fatigue limit. A 60-year environmental CUF was therefore, recalculated using real plant data obtained by using the FatiguePro fatigue monitoring software at this location, and reduced below the ASME Code Section III Class 1 fatigue limit of 1.0.

The staff evaluated the applicant's response and found it acceptable. It conforms with the staff position on environmental effects on fatigue. The staff's concern described in RAI 4.3.10-2 is resolved.

On the basis of its review, the staff found that the environmental fatigue TLAAs of components listed in NUREG/CR 6260 for early-vintage Westinghouse plants and the pressurizer will remain valid to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

4.3.10.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of environmental effects on fatigue in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on environmental effects on fatigue and, is therefore, acceptable.

4.3.10.4 Conclusion

The staff reviewed the applicant's TLAA on environmental effects on fatigue, as summarized in LRA Section 4.3.10, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for environmental effects on fatigue complies with the staff's acceptance criterion for TLAAs in 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 FSAR supplement contains an appropriate summary description of the TLAA on environmental effects on fatigue for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.11 Containment Liner Plate Fatigue Analysis

4.3.11.1 Summary of Technical Information in the Application

In LRA Section 4.3.11, the applicant stated that the interior of each containment is lined with a welded steel plate liner which provides an essentially leak-tight barrier. Design criteria are applied to the liner to assure that the specified allowed leak rate is not exceeded under design-basis accident conditions. The following fatigue loads, as described in FSAR Section 5.1, were considered in the design of the liner plate and are considered a TLAA for the purposes of license renewal:

(1) Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is 40 for the plant life of 40 years.

(2) Thermal cycling due to containment interior temperature varying during the startup and shutdown of the reactor system. The number of cycles for this loading is assumed to be 500.

(3) Thermal cycling due to the design-basis accident is assumed to be one cycle.

(4) Thermal cycling due to the high-temperature piping systems passing through the penetrations. These systems are partially isolated from the liner plate penetrations by concentric sleeves between the pipe and the liner plate. The attachment sleeves are designed in accordance with ASME Code Section III. All penetrations were reviewed for a conservative number of cycles to be expected during the life of the plant.

Each of the above items has been evaluated for the period of extended operation.

For item (1), the number of thermal cycles due to annual outdoor temperature variations was increased from 40 to 60 for the period of extended operation. The effect of this increase is insignificant in comparison to the assumed 500 thermal cycles due to containment interior temperature varying during heatup and cooldown of the RCS. The 500 thermal cycles includes a margin of 300 thermal cycles above the 200 RCS allowable design heatup and cooldown cycles, which is sufficient to accommodate the additional 20 cycles of annual outdoor temperature variation. Therefore, the applicant concluded that this loading condition is considered valid for the period of extended operation as it is enveloped by item (2).

For item (2), the assumed 500 thermal cycle loading was evaluated based on the more limiting heatup and cooldown design cycles (transients) for the major components of the RCS. The major components of the RCS were designed to withstand 200 heatup and cooldown thermal cycles. The originally projected number of maximum RCS design cycles envelops the projected cycles for the period of extended operation. The actual number of RCS transients is also monitored to confirm that the system design transients are not exceeded. Transient monitoring was described in LRA Section B3.2, Fatigue Monitoring Program. Therefore, the applicant concluded that the original containment liner plate fatigue analysis for 500 heatup and cooldown cycles is considered valid for the period of extended operation.

For item (3), the assumed value for thermal cycling due to the maximum hypothetical accident remains valid. No maximum hypothetical accident occurred and none is expected; therefore, this assumption is considered valid for the period of extended operation.

For item (4), the applicant stated that design of the containment penetrations has been reviewed. The liner plate (including penetration extension sleeves) incorporated the design guidance of ASME Code Section III, 1965 Edition, Article 4, paragraphs N-412(m), N-414.5, N-412(n), and N-415.1; Figures N-414, and N-415(A); and Table N-413. The containment penetrations also conform to the applicable sections of ASA N6.2-1965, "Safety Standard for the Design, Fabrication, and Maintenance of Steel Containment Structures for Stationary Nuclear Power Reactors." The containment penetration head fittings were designed, fabricated, inspected, and tested in accordance with ASME Code Section III, Class B, 1968 Edition and all Addenda. The main steam, feedwater, blowdown, and letdown systems are the only piping systems penetrating the containment that could contribute significant thermal loading on the liner plate. Due to the higher operating temperature, the main steam piping penetrations were considered bounding and, therefore, evaluated through the period of extended operation. ASME Code, Section III, 1965, paragraph N-415.1, states that a fatigue analysis is not required, provided the service loading of the vessel or component meets six specified conditions. For the penetration sleeves and the sleeve end-fittings connecting the pressure piping to the sleeves, analyses were performed which verified that all six conditions of paragraph N-415.1 are met for the period of extended operation.

4.3.11.2 Staff Evaluation

Containment liner plates and penetrations were evaluated for (1) thermal cycling due to annual outdoor temperature variations at one cycle per year, (2) 500 assumed cycles of thermal cycling due to containment interior temperature varying during the startup and shutdown of the reactor system, (3) thermal cycling due to a design-basis accident which is assumed to be one cycle, (4) and thermal cycling due to the high temperature piping systems passing through the penetrations. The applicant stated that these systems are partially isolated from the liner plate penetrations by concentric sleeves between the pipe and the liner plate. The attachment sleeves are designed in accordance with ASME Code Section III, 1965 Edition. All penetrations were reviewed for a conservative number of cycles to be expected during the life of the plant. Each item was evaluated for the period of extended operation.

On the basis of its review, the staff found that the applicant had demonstrated that the fatigue TLAAs associated with the Units 1 and 2 containment liner plate and penetrations will remain valid for the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(i).

4.3.11.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of containment liner plate fatigue analysis in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on containment liner plate fatigue analysis and, is therefore, acceptable.

4.3.11.4 Conclusion

The staff reviewed the applicant's TLAA on containment liner plate fatigue analysis, as summarized in LRA Section 4.3.11, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for containment liner plate fatigue analysis complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(i), 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 FSAR supplement contains an appropriate summary description of the TLAA on containment liner plate fatigue analysis for the period of extended operation, as required by 10 CFR 54.21(d).

4.3.12 Spent Fuel Pool Liner Fatigue Analysis

4.3.12.1 Summary of Technical Information in the Application

The applicant stated that the surfaces of the spent fuel pool, fuel transfer canals, and refueling cavities are lined with stainless steel sheet material. The liner provides a leak-tight barrier for spent fuel storage and fuel transfer operations, and consists of stainless steel sheets welded to a system of embedments in the reinforced concrete structures. These concrete structures and the liner are seismically designed. The liner serves no structural function; therefore, fatigue was not a design consideration. On this basis, the applicant concluded that fatigue is not a TLAA for the spent fuel pool liner.

4.3.12.2 Staff Evaluation

The applicant stated that the liner of the spent fuel pool serves no structural function. Metal fatigue was, therefore, not a design consideration. Therefore, the applicant concluded that fatigue is not a TLAA for the spent fuel pool liner. The staff agreed that spent fuel pool liner fatigue is not identified as a TLAA, in accordance with the definitions in 10 CFR 54.3.

4.3.12.3 FSAR Supplement

Spent fuel pool liner fatigue is not identified as a TLAA, therefore, an FSAR supplement is not required.

4.3.12.4 Conclusion

Because the liner of the spent fuel pool serves no structural function, and metal fatigue was not a design consideration, the staff concluded that the spent fuel liner is not identified as a TLAA in accordance with the definitions in 10 CFR 54.3.

4.3.13 Crane Load Cycle Limit

4.3.13.1 Summary of Technical Information in the Application

The following cranes are included in license renewal scope and in NUREG-0612: containment polar cranes, auxiliary building crane, and turbine hall crane. The load cycle limit for PBNP cranes was identified as a TLAA.

All PBNP cranes were designed and constructed to meet the requirements of Specification 61 of the Electric Overhead Crane Institute (EOCI-61). EOCI-61 did not require a specific fatigue analysis. As such, there are no specific fatigue analyses for PBNP cranes.

The containment polar cranes and the turbine hall crane are used primarily during refueling outages. The PBNP primary auxiliary building (PAB) crane is used primarily in support of material receipt, spent fuel cask transfers, and radwaste cask transfers. Occasionally, these cranes make lifts at, or near, their rated capacity; however, the majority of the crane lifts are substantially less than their rated capacity. Based on conservative usage assumptions, the above-listed cranes are expected to make 50,000 partial load lifts and less than 5,000 at, or near, rated load lifts over a 60-year operating period. This is significantly less than the Crane Manufacturers Association of America, Specification 70 (CMAA-70) design cycle limit for Class "A" service cranes.

The specifications for the traveling cranes included rated overload cycle limits of roughly two 125 percent rated load lifts per year, and three 150 percent rated load lifts in the cranes' lifetime. With the exception of the containment polar cranes, no lifts in excess of the rated load were made. Each containment polar crane was used to support its respective unit's Steam Generator Replacement Project. These lifts, related to the containment polar cranes, were specifically analyzed and engineered taking into consideration the replacement trolleys, bridge strengthening, and temporary center poles to ensure that the original design capabilities of the cranes were not degraded. Therefore, since the major cranes are not used to make routine over-rated load lifts, and since special one-time over-rated load maintenance lifts are addressed as specific engineered lifts, the applicant concluded that the original specified cycle limits for over-rated load lifts will not be exceeded during the extended period of operation.

4.3.13.2 Staff Evaluation

The staff's review of LRA Section 4.3.13 identified an area in which additional information was necessary to complete the review of the crane load cycle limit evaluation. The applicant responded to the staff's RAI as discussed below.

RAI 4.3.13-1. LRA Section 4.3.13 states that the load limits of the containment polar, auxiliary building, and turbine hall cranes are designed in accordance with CMAA-70 Class "A" service for 20,000 to 200,000 load cycles; and based on conservative usage assumptions, the cranes are expected to make 50,000 partial load lifts and less than 5,000 at, or near, rated load lifts for the period of extended operation. In RAI 4.3.13-1, dated November 18, 2004, the staff requested the applicant to provide the basis for concluding that 50,000 partial load lifts and less than 5,000 at, or near, rated load lifts are in accordance with design of 20,000 to 200,000 load cycles.

In its response, dated January 7, 2005, the applicant cited an earlier submittal to the NRC, dated January 11, 1982, regarding the control of heavy loads, which is excerpted below:

> CMAA Specification 70 and ANSI B30.2-1976 apply to the Containment Building, Turbine Building and Auxiliary Building Cranes.
>
> The Containment Building, Turbine Building and Auxiliary Building Cranes were designed to comply with EOCI Specification 61, which was superceded by CMAA Specification 70. The difference between these two specifications which impact the evaluation of the safe handling of heavy loads are addressed below with respect to the Containment and Turbine Building Cranes. The Auxiliary Building Crane will be modified to provide adequate redundant lifting features. The modification will take into consideration the requirements of CMAA Specification 70 and ANSI B30.2-1976 and the guidance of Regulatory Guide 1.13.
>
> It is to be noted that the Franklin Research Center, a division of the Franklin Institute, conducted a comparison of the recommendations of CMAA-70 with those contained in EOCI-61. Generally, the requirements of CMAA-70 represent the codification of good engineering practice which should have been incorporated in cranes built to EOCI-61 specification although specific requirements were not contained in EOCI-61. The Franklin Research Center study is addressed in "Technical Evaluation Report," NRC Docket No. 50-334, dated September 24, 1981, performed under NRC Contract No. NRC-03-79-118.

The applicant further stated:

> CMAA-70, Article 3.3.3.1.3 provides substantial guidance with respect to fatigue failure by indicating allowable stress ranges for various structural members in joints under repeated loads. EOCI-61 does not address fatigue failure. The requirements of CMAA-70 are not of consequence for the Containment Building and Turbine Building Cranes since these cranes are not generally subjected to frequent loads at or near design conditions (CMAA-70 provides allowable stress ranges for loading cycles in excess of 20,000 cycles) and are not generally subjected to stress reversal

(CMAA-70 allowable stress range is reduced to below the basic allowable stress for only a limited number of joint configurations).

As stated in response to RAI 4.3.13-1, a rated load lift is considered as equal to or greater than 50 percent of the crane's rating. A partial load lift is less than 50 percent of the crane's rating. The primary auxiliary building (PAB) crane is the most limiting for rated load lifts, while the containment crane is most limiting for partial load lifts.

The conservative usage assumptions for the two cranes are:

- PAB crane - Usage is comprised of three components: fuel cask lifts (NUHOMS), maintenance loads, and original fuel casks (VSC-24). The estimated number of lifts is 2700, 600, and 892 respectively, totaling less than 5,000 lifts for the 60-year life of the plant.
- containment crane - It is assumed that a total of 60 outages, with 20 days of lifting per outage, and a total of 40 lifts per day will produce a total of less than 50,000 lifts for the 60-year life of the plant.

On the basis of its review and the RAI response discussed above, the staff determined that fatigue failure is not likely for the containment building and PAB cranes because the applicant provided adequate justification for concluding that 50,000 partial load lifts and less than 5000 at, or near, rated load lifts are in accordance with the design-load cycles. The staff's concern described in RAI 4.3.13-1 is resolved.

4.3.13.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of crane load cycle limit in LRA Section A15.4.2. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on crane load cycle limit and, is therefore, acceptable.

4.3.13.4 Conclusion

The staff reviewed the applicant's TLAA on crane load cycle limits, as summarized in LRA Section 4.3.13, and determined that the metal fatigue assessments at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for crane load cycle limits complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(i), 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 FSAR supplement contains an appropriate summary description of the TLAA on crane load cycle limit for the period of extended operation, as required by 10 CFR 54.21(d).

4.4 Fracture Mechanics Analysis

4.4.1 Reactor Vessel Underclad Cracking

Reactor vessel underclad cracks were first discovered in October 1970 during examination of the Atucha reactor vessel (RV). They were reported to exist only in SA-508, Class 2 RV forgings manufactured to a coarse grain practice and clad by high-heat-input submerged arc processes. The underclad cracking issue was first addressed by Westinghouse topical report WCAP-7733, which justified the continued operation of Westinghouse plants for 32 EFPYs. Subsequently, Westinghouse submitted WCAP-15338, which extended the analysis to justify operation of Westinghouse plants for 60 calendar years of plant operation. The staff review of WCAP-15338 is contained in a September 25, 2003, letter to R.A. Newton (Westinghouse Owners Group) and concluded that LRAs should include two action items:

(1) The license renewal applicant is to verify that its plant is bounded by the WCAP-15338 report. Specifically, the renewal applicant is to indicate whether the number of design cycles and transients assumed in the WCAP-15338 analysis bounds the number of cycles for 60 years of operation of its RV.

(2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA for the period of extended operation. Those applicants for license renewal referencing the WCAP-15338 report for the RV components shall ensure that the evaluation of the TLAA is summarily described in the FSAR supplement.

4.4.1.1 Summary of Technical Information in the Application

The applicant indicated that the Units 1 and 2 RVs have neither underclad reheat cracking nor underclad cold cracking because the vessel manufacturers did not use the welding processes, post-weld heat treating practices, or materials that contributed to the cracking conditions. Specifically, the applicant stated that single layer cladding was applied using one-wire cladding processes with low-heat input that did not exhibit underclad reheat cracking in evaluations of either test samples or actual nozzle cutouts. Multiple layer cladding had preheating and post-heating applied during the cladding processes, precluding underclad cold cracking.

4.4.1.2 Staff Evaluation

The applicant confirmed that the vessel manufacturers did not use the welding processes, post-weld heat treating practices, or materials that contributed to the underclad cracking conditions in other vessels. The staff agreed that reactor vessel underclad cracking is not an applicable TLAA.

4.4.1.3 FSAR Supplement

Reactor vessel underclad cracking is not considered a TLAA at Units 1 and 2. Therefore, an FSAR supplement summary description is not required.

4.4.1.4 Conclusion

The staff reviewed the applicant's TLAA on reactor vessel underclad cracking, as summarized in LRA Section 4.4.1, and concluded that underclad cracking is not an applicable TLAA for PBNP. The staff also concluded that an FSAR supplement on reactor vessel underclad cracking is not required.

4.4.2 Reactor Coolant Pump Flywheel Analysis

The function of the reactor coolant pump (RCP) in the reactor coolant system (RCS) of a PWR plant is to maintain an adequate cooling flow rate by circulating a large volume of primary coolant water at high temperature and pressure through the RCS. A concern about overspeed of the RCP and its potential for failure led to the issuance of Regulatory Guide (RG) 1.14, "Reactor Coolant Pump Flywheel Integrity," in 1971. The regulatory position of RG 1.14 concerning ISI calls for an in-place ultrasonic volumetric examination of the areas of higher stress concentration at the bore and keyway at approximately 3-year intervals and a surface examination of all exposed surfaces and complete ultrasonic volumetric examination at approximately 10-year intervals. The flywheel inspection schedule is to coincide with the individual plant's ISI schedule as required by ASME Code Section XI.

In January 1996, Westinghouse submitted WCAP-14535, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination." This report, which provides an engineering analysis based on fracture mechanics, is intended to eliminate RCP flywheel ISI requirements for all operating Westinghouse plants and some B&W plants. However, the NRC safety evaluation of WCAP-14535, dated January 1996, stated, "the staff believes that even for flywheels meeting all the design criteria of RG 1.14, as modified in this SER, inspections should not be completely eliminated." The NRC safety evaluation states:

> ... the staff finds the following acceptable:
>
> (1) Licensees who plan to submit a plant-specific application of this topical report for flywheels made of SA 533 B material need to confirm that their flywheels are made of SA 533 B material. Further, licensees having Group-15 flywheels need to demonstrate that material properties of their A516 material is equivalent to SA 533 B material, and its reference temperature, RT_{NDT}, is less than 30 °F.
>
> (2) Licensees who plan to submit a plant-specific application of this topical report for their flywheels not made of SA 533 B or A516 material need to either demonstrate that their flywheel material properties are bounded by those of SA 533 B material, or provide the minimum specified ultimate tensile stress, S_u, the fracture toughness, K_{IC}, and the reference temperature, RT_{NDT}, for that material. For the latter, the licensees should employ these material properties, and use the methodology in the topical report, as extended in the two responses to the staff's RAI, to provide an assessment to justify a change in inspection schedule for their plants.
>
> (3) Licensees meeting either (1) or (2) above should either conduct a qualified in-place ultrasonic examination (UT) over the volume from the

inner bore of the flywheel to the circle of one-half the outer radius or conduct a surface examination (MT and/or PT) of exposed surfaces defined by the volume of the disassembled flywheels once every 10 years. The staff considers this 10-year inspection requirement not burdensome when the flywheel inspection is conducted during scheduled ISI inspection or RCP motor maintenance. This would provide an appropriate level of defense in depth.

4.4.2.1 Summary of Technical Information in the Application

RG 1.14, Revision 1, dated August 1975, provides the staff's recommended acceptance criteria regarding material specifications and Westinghouse Topical Report WCAP-14535 presents an evaluation of the probability of failure over an extended operating period of 60 years. This report demonstrates that the flywheel design has a high structural reliability with very high flaw tolerance and negligible flaw crack extension over a 60-year service life. The NRC reviewed and approved WCAP-14535-A for application with certain conditions and limitations. In the LRA, the applicant verified the RCP flywheel material and invoked this analysis for reducing the frequency of performing RCP flywheel inspections.

4.4.2.2 Staff Evaluation

The staff's review of LRA Section 4.4.2 identified an area in which additional information was necessary to complete the review of the RCP Flywheel Analysis evaluation. The applicant responded to the staff's RAI as discussed below.

RG 1.14, Revision 1, provides the staff's recommended acceptance criteria for material and minimum fracture toughness properties of SA 508, Class 2 and 3 materials and SA 533 Grade B, Class 2 materials used in the fabrication of U.S. RCP flywheels. RG 1.14, Revision 1, also provides acceptable guidelines for performing the structural integrity assessments for the RCP flywheels in U.S. light-water reactors, including the assessments for ensuring the integrity of the flywheels against unacceptable fatigue-induced crack growth failures. These fatigue assessments are based on fatigue-induced crack growth associated with the number of start/stop cycles assumed in the design basis for the pumps. Therefore, to meet the acceptance criterion of 10 CFR 54.21(c)(1)(i), the applicant is required to demonstrate that the total number of RCP start/stop cycles projected through the end of the extended periods of operation for each of the units will be bounded by the number of RCP start/stop cycles assumed in the 60-year fatigue-induced crack growth analysis for the RCP flywheels (*i.e.*, based on a bounding analysis of 6000 RCP start/stop cycles).

An evaluation of the probability of failure over the period of extended operation was performed in WCAP-14535-A, dated January 1996, for all operating Westinghouse plants and certain B&W plants. It demonstrated that the flywheel design had a high structural reliability with very high flaw tolerance and negligible flaw crack extension over a 60-year service life. The NRC reviewed and approved the evaluation.

<u>RAI 4.4.2</u>. In RAI 4.4.2, dated November 17, 2004, the staff requested the applicant to provide the number of RCP start/stop cycles that are assumed in the 60-year RCP flywheel fatigue crack growth assessment for PBNP.

In its response, dated January 25, 2005, the applicant confirmed that the conservative estimation for the number of RCP start/stop cycles will be 500 for the 60-year extended life. This estimated number of cycles is well below the assumed RCP cycles of 6000 in the Westinghouse document and, therefore, PBNP RCP flywheels are bounded by the Westinghouse analysis.

On the basis of its review and the above discussion, the staff concluded that the TLAA for RCP flywheels, as provided in LRA Section 4.4.2, is in compliance with 10 CFR 54.21(c)(1)(i). The applicant's response is acceptable and, therefore, the staff's concern described in RAI 4.4.2 is resolved.

4.4.2.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include 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 the following FSAR supplement summary description for the TLAA on fatigue-induced crack growth of the RCP flywheels:

> An evaluation of the probability of failure over the period of extended operation was performed in WCAP-14535-A for all operating Westinghouse plants and certain Babcock and Wilcox plants. It demonstrates that flywheel design has a high structural reliability with a very high flaw tolerance and negligible flaw crack extension over a 60-year service life. PBNP verified the RCP flywheel material and invoked this analysis as the basis for reducing the frequency of performing RCP flywheel inspections. The analysis associated with the structural integrity of the reactor coolant pump flywheel has been evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

The applicant provided an FSAR supplement summary description for the RCP flywheels in LRA Section A15.4.3. It provides a reference to WCAP-14535-A and reflects the LRA as supplemented by letter dated January 25, 2005. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on RCP flywheels and, is therefore, acceptable.

4.4.2.4 Conclusion

The staff reviewed the applicant's TLAA on RCP Flywheel Analysis, as summarized in LRA Section 4.4.2, and determined that the fracture mechanics analyses at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for RCP Flywheel Analysis complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(i), 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 FSAR supplement contains an appropriate summary description of the TLAA on RCP Flywheel Analysis for the period of extended operation, as required by 10 CFR 54.21(d).

4.4.3 Reactor Coolant Pump Casing Analysis (ASME Code Case N-481 Analysis)

4.4.3.1 Summary of Technical Information in the Application

In LRA Section 4.4.3 the applicant stated that the ASME Section XI Code, up to and including the 1998 Edition, required a volumetric inspection of the RCP casing welds, and a visual inspection of the pressure boundary components. In lieu of performing the required Section XI internal visual and volumetric inspections of RCP CASS casings, a fracture mechanics analysis, supplemented by visual examinations, per the requirements of ASME Code Case N-481 was performed for the original operating period of 40 years. This analysis is contained in the generic industry WCAP-13045, and the PBNP-specific WCAP-14705. These analyses incorporated the effects of thermal embrittlement, and demonstrated compliance with Code Case N-481, *requirements for the original 40-year operating license period.*

The current ASME Section XI Code applicable for PBNP is the 1998 Edition with all addenda through 2000. The NRC approved the use of this ASME Code edition at PBNP via SER, dated November 6, 2001. This Code does not require pump casing weld volumetric, or routine internal visual examinations; however, it does require external surface examinations of the casing welds, and internal visual examinations when the RCP is disassembled for other reasons. The applicant stated that the fracture mechanics analysis would not be revised and resubmitted to the NRC for the extended period of operation in support of applying Code Case N-481 and, therefore, is not a TLAA.

4.4.3.2 Staff Evaluation

The staff's review of LRA Section 4.4.3 identified an area in which additional information was necessary to complete the review of the RCP casing analysis evaluation. The applicant responded to the staff's RAI as discussed below.

RAI 4.4.3-1. LRA Section 4.4.3 indicates that the applicant re-evaluated the fracture mechanics analyses to ASME Code Case N-481 documented in WCAP-13045 and WCAP-14705 for the Units 1 and 2 RCP casings and they remain valid for the 60-year extended license operating period. The LRA indicates that these components are not susceptible to thermal aging because they satisfy the criteria in the NRC safety evaluation for WCAP-14575-A. The LRA also indicates that the fracture mechanics analysis would not be revised and resubmitted to the NRC for the extended period of operation because the Code Case has been superceded by the ASME Code and the analysis is no longer needed. In RAI 4.4.3-1, dated February 7, 2005, the staff requested the applicant to evaluate the ASME Code Case N-481 analysis to the criteria for TLAA in 10 CFR 54.3 to determine whether the analysis satisfies the criteria and should be considered a TLAA. If it satisfied the TLAA criteria, the applicant was requested to identify the changes to the analysis that result from the proposed additional 20 years of facility operation and to provide the results of the analysis that satisfy 10 CFR 54.21(c)(1)(i), (ii) or (iii).

In its response, dated March 4, 2005, the applicant stated the following:

> The reactor coolant pump integrity analysis is not a time-limited aging analyses (TLAA) for PBNP. As defined in 10 CFR 54.3(a), time-limited aging analyses, for the purposes of this part, are those licensee calculations and analyses that:
>
> - Involve systems, structures, and components within the scope of license renewal, as delineated in §54.4(a);
> - Consider the effects of aging;
> - Involve time-limited assumptions defined by the current operating term, for example, 40 years;
> - Were determined to be relevant by the licensee in making a safety determination;
> - 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 §54.4(b); and
> - Are contained or incorporated by reference in the CLB.
>
> The ASME Section XI Code, up to and including the 1998 Edition, required a volumetric inspection of the RCP casing welds, and a visual inspection of the pressure boundary components. In lieu of performing the required Section XI internal visual and volumetric inspections of RCP cast austenitic stainless steel (CASS) casings, a fracture mechanics analysis, supplemented by visual examinations, per the requirements of ASME Code Case N-481 was performed for the original operating period of 40 years. This analysis is contained in the generic industry WCAP-13045, and the PBNP specific WCAP-14705. These analyses incorporated the effects of thermal embrittlement and demonstrated compliance with Code Case N-481 requirements for the original 40-year operating license period.
>
> The current ASME Section XI Code applicable for PBNP is the 1998 Edition of the Code with Addenda through 2000. The NRC approved the use of this ASME Code Edition at PBNP with an NRC safety evaluation dated November 6, 2001. This Code does not require pump casing weld volumetric, or routine internal visual examinations; however, it does require external surface examinations of the casing welds and internal visual examinations when the RCP is disassembled for other reasons. Since RCP volumetric examinations are no longer required by the ASME Section XI Code, the fracture mechanics analysis providing the basis for invoking Code Case N-481 is no longer needed and is no longer a part of the CLB. Thus, the fracture mechanics analysis for applying Code Case N-481 does not meet the six criteria for defining a TLAA per 10 CFR 54.3 and is not a TLAA for PBNP.
>
> The generic technical report (GTR) for Class 1 Piping and Associated Pressure Boundary Components, WCAP-I4575-A, identifies that a fracture mechanics analysis performed for the extended operating period is an acceptable means of managing thermal aging of CASS. The NRC SER for the GTR for Class 1 Piping and Associated Pressure Boundary Components, WCAP-14575-A, provides delta-ferrite and

Molybdenum screening criteria to determine if the CASS material is susceptible to thermal aging. The generic industry WCAP-13045 identifies that the delta-ferrite content for all the PBNP Unit's RCP casing castings is less than 10%, and the Molybdenum content is 0.20 percent. The PBNP pump casing castings are not considered susceptible to thermal aging per the screening criteria. Thus, a RCP's structural integrity analysis for managing thermal aging at PBNP is not necessary.

As a result of the above information, LRA Section 4.4.3, "Reactor Coolant Pump Casing Analysis (ASME Code Case N-481 Analysis)," was deleted by the applicant from the LRA.

On the basis of its review and RAI response, the staff found deletion of LRA Section 4.4.3 acceptable. RCP casing analysis is not considered a TLAA, in accordance with the definition of 10 CFR 54.3. The staff's concern described in RAI 4.4.3-1 is resolved.

4.4.3.3 FSAR Supplement

The RCP casing is not identified as a TLAA, therefore, an FSAR supplement is not required. Furthermore, the applicant has deleted LRA Section 4.4.3.

4.4.3.4 Conclusion

The RCP casings are not considered susceptible to thermal aging. Therefore, a structural integrity analysis is not necessary. The staff concluded that the RCP casing analysis is not identified as a TLAA, in accordance with the definitions of 10 CFR 54.3. Furthermore, in response to the staff's RAI the applicant deleted LRA Section 4.4.3.

4.4.4 Reactor Coolant System Main Loop Piping Leak-Before-Break Analysis

4.4.4.1 Summary of Technical Information in the Application

The applicant stated that the original structural design basis of the PBNP Class 1 piping systems required consideration of dynamic effects resulting from non-mechanistic circumferential pipe breaks, and that protective measures for such breaks be incorporated into the plant design. Subsequent to the original design, a new concern regarding asymmetric blowdown loads was identified in 1975. These asymmetric blowdown loads could cause pressure imbalance loads both internal and external to the RCS. According to the applicant, the loads could cause previously unconsidered damage to the RCS equipment. The NRC designated this an unresolved safety issue (USI) "A-2" (Asymmetric Blowdown Loads on the RCS). Westinghouse addressed this USI on a generic basis.

The applicant stated that the NRC reviewed and approved the generic Westinghouse leak-before-break (LBB) evaluation(s) in NRC Generic Letter (GL) 84-04. The NRC requested that PBNP incorporate the generic LBB analysis for the RCS main loop piping to eliminate from the design basis the consideration of dynamic effects of postulated ruptures in primary coolant loop piping. By letter dated May 30,1985, Wisconsin Electric requested an exemption from 10 CFR 50, Appendix A, General Design Criterion (GDC) 4, based on the generic Westinghouse LBB analysis. In 1986, the NRC revised 10 CFR 50 Appendix A, GDC 4, to allow the use of LBB technology for excluding from the design basis the dynamic effects of postulated ruptures in primary coolant loop piping in pressurized water reactors. By letter dated May 6, 1986, the NRC stated that Wisconsin Electric's request for an exemption was not necessary due to the revision to 10 CFR 50, Appendix A, GDC 4, and acknowledged that PBNP was bounded by the generic Westinghouse LBB analysis and met the additional criteria identified in NRC GL 84-04.

The applicant stated that plant-specific LBB analysis for Units 1 and 2, primary coolant loop piping was performed by Westinghouse in 1996, and revised in 2002 and 2003. The results of the current LBB analysis are documented in WCAP-14439, Revision 2. The report demonstrates compliance with LBB technology for the RCS piping based on plant-specific analysis, using the methodology and criteria of SRP Section 3.6.3. The revised LBB analysis incorporates analysis parameters associated with power uprate conditions, and a 60-year operating period. This revision documents RCS main loop piping geometry, loading, and material properties used in the fracture mechanics evaluation. Since the primary loop piping systems include cast stainless steel fittings, EOL (60-year) fracture toughness calculations considering the effects of thermal aging were determined for each heat of material.

Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which LBB crack stability evaluations were made. Through-wall flaw sizes were identified that would cause a leak at a rate of ten times the leakage detection subsystem capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, by analyzing plant-specific transients and cycles, the fatigue crack growth for the 60 years was shown to be acceptable for the primary loop piping. The applicant concluded that all the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

4.4.4.2 Staff Evaluation

The successful application of LBB to Units 1 and 2 RCS primary loop piping is described in Technical Report WCAP-14439, Revision 2, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the PBNP Nuclear Plant Units 1 and 2 for the Power Uprate and License Renewal Program," dated September 2003. This report provides the technical basis for evaluating postulated flaw growth in the main RCS piping under normal plus-faulted loading conditions. The LBB crack stability evaluations were performed for enveloping critical locations. Also, for a postulated flaw, a fatigue crack growth analysis was carried out to demonstrate that fatigue crack growth was negligible over 60 years. The staff concluded that this LBB analysis meets the definition of a TLAA per NUREG-1800 Section 4.1.

Pursuant to 10 CFR 54.21(c)(1)(ii), the applicant projected the analyses to the end of the period of extended operation by reanalysis. The applicant indicated that the analyses were revised incorporating revised analysis parameters associated with power uprate conditions and a 60-year operating period. The applicant stated that since the primary loop piping contains cast stainless steel material, the thermal aging of the CASS material of the piping was considered for the period of extended operation.

Since the V.C. Summer main coolant loop weld cracking event involving Alloy 82/182 weld material, the staff has been addressing the effect of primary water stress corrosion cracking

(PWSCC) on Alloy 82/182 piping welds on a generic basis for all currently operating PWR plants. To resolve this current operating issue, the industry is taking the initiative to (1) develop overall inspection and evaluation guidance, (2) assess the current inspection technology, and (3) assess the current repair and mitigation technology. An interim industry report, "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plants (MRP-44), Part 1: Alloy 82/182 Pipe Butt Welds," dated April 2001, justifies the continued operation of PWR plants while the industry completes the development of the final report. The staff documented its acceptance of this interim report in a safety evaluation dated June 14, 2001. The final industry report, "Alloy 82/182 Pipe Butt Weld Safety Assessment for U.S. PWR Plant Designs (MRP-113)," was issued in July 2004. Pending the staff's review of this report and additional UT inspection data from piping involving Alloy 82/182 weld material from the industry, the staff is pursuing resolution of this current operating issue pursuant to 10 CFR Part 50. The Reactor Coolant System Alloy 600 Inspection Program is documented in SER Section 3.0.3.2.15. Based on the discussion above and the staff's evaluation of the Reactor Coolant System Alloy 600 Inspection Program, the staff concluded that the LBB reanalysis adequately addresses the period of extended operation and, is therefore, acceptable.

4.4.4.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 FSAR supplement summary description of RCS main loop piping LBB in LRA Section A15.4.3. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on RCS main loop piping LBB and, is therefore, acceptable.

4.4.4.4 Conclusion

The staff reviewed the applicant's TLAA on RCS main loop piping LBB, as summarized in LRA Section 4.4.4, and determined that the fracture mechanics analyses at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for RCS main loop piping LBB complies with the staff's acceptance criterion for TLAAs in 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 FSAR supplement contains an appropriate summary description of the TLAA on RCS main loop piping LBB for the period of extended operation, as required by 10 CFR 54.21(d).

4.4.5 Pressurizer Surge Line Piping Leak-Before-Break Analysis

4.4.5.1 Summary of Technical Information in the Application

The applicant stated that the LBB analysis for Units 1 and 2 pressurizer surge line piping was performed in 1998. The results of the analysis are documented in WCAP-15065. The report demonstrates compliance with LBB technology for the pressurizer surge line piping based on plant-specific analysis. Westinghouse revised WCAP-15065 to include the NRC safety evaluation dated December 15, 2000, approving the LBB analysis for the PBNP Units 1 and 2 pressurizer surge line piping. This revision is documented in WCAP-15065-P-A, Revision 1. The pressurizer surge line LBB analysis incorporates analysis parameters associated with original licensed power conditions and a 40-year operating period. The LBB analysis includes the effects of thermal stratification, as evaluated for the PBNP surge lines in WCAP-13509. WCAP-15065-P-A documents pressurizer surge line piping geometry, loading, and material properties used in the fracture mechanics evaluation. The applicant stated that the pressurizer surge line piping does not include cast stainless steel fittings.

The applicant stated that the analysis is consistent with the criteria specified in NUREG-1061 Volume 3, "Report of the U.S. NRC Piping Review Committee, Evaluation of Potential for Pipe Breaks," using the modified limit load method as specified in SRP, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which LBB crack stability evaluations were made. Through-wall flaw sizes were identified which would cause a leak at a rate of ten times the leakage detection subsystem capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, by analyzing plant-specific transients and cycles, the fatigue crack growth for the 40 years was shown to be acceptable for the pressurizer surge line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied. The pressurizer surge line LBB analysis was further evaluated to determine the impacts of uprated power conditions and a 60-year operating period. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast piping fittings contained in the piping system; therefore, the applicant concluded that thermal aging is not an issue for the period of extended operation. Thermal aging of the stainless steel weld material was considered with saturated conditions (fully aged) and, therefore, is valid for the period of extended operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis. The impacts of changes in NSSS design conditions, and the 60-year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15065-P-A, remained unchanged.

The applicant concluded that the pressurizer surge line LBB analysis was evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The applicant further concluded that dynamic effects of pressurizer surge line pipe breaks need not be considered in the structural design basis of Units 1 and 2 for the license renewal operating period.

4.4.5.2 Staff Evaluation

The applicant identified critical locations and performed LBB crack stability evaluations based on loading, pipe geometry, and fracture toughness considerations. The applicant concluded that enveloping critical locations were determined at which LBB crack stability evaluations were made. The resultant through-wall cracks offered leak rates sufficiently large enough to be detected by the plant's leakage detection system without pipe breakage.

The applicant determined, by assessing plant-specific transients and cycles, that the fatigue crack growth for the 40-year operating period are acceptable for the pressurizer surge line piping and all margins are satisfied for the 40-year operating period.

LBB analyses were evaluated considering the effects of power uprate and a 60-year operating period. It was indicated that there is no CASS in the pressurizer surge line, therefore, the staff concluded that thermal aging effects are not a concern. Furthermore, the applicant demonstrated that the transients and cycles for the 60-year period were bounded by the LBB analysis of the 40-year period and that there were no design changes due to the power uprate.

Based on the fact that the number of cycles are bounded during the period of extended operation, the staff concluded that pursuant to 10 CFR 54.21(c)(1)(i), the applicant demonstrated that the existing analyses are valid for the period of extended operation, and are therefore, acceptable.

4.4.5.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 FSAR supplement summary description of pressurizer surge line piping LBB in LRA Section A15.4.3. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on pressurizer surge line piping LBB and, is therefore, acceptable.

4.4.5.4 Conclusion

The staff reviewed the applicant's TLAA on pressurizer surge line piping LBB, as summarized in LRA Section 4.4.5, and determined that the fracture mechanics analyses at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for pressurizer surge line piping LBB complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(i), 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 FSAR supplement contains an appropriate summary description of the TLAA on pressurizer surge line piping LBB for the period of extended operation, as required by 10 CFR 54.21(d).

4.4.6 Class 1 Accumulator Injection Line Piping Leak-Before-Break Analysis

4.4.6.1 Summary of Technical Information in the Application

The applicant stated that the LBB analysis for Units 1 and 2 accumulator injection line piping was performed in 1998. The scope of the analysis for the accumulator injection lines included the residual heat removal (RHR) return line, and the results are documented in WCAP-15107. The report demonstrates compliance with LBB technology for the PBNP accumulator injection line piping based on plant-specific analysis. Westinghouse revised WCAP-15107 to include the NRC safety evaluation approving the LBB analysis for Units 1 and 2 accumulator injection line piping in 2001. This revision is documented in WCAP-15107-P-A, Revision 1. The accumulator injection line LBB analysis incorporates analysis parameters associated with original licensed power conditions and a 40-year operating period. WCAP-15107-P-A documents accumulator injection line piping geometry, loading, and material properties used in the fracture mechanics evaluation. The applicant stated that the accumulator injection line piping does not include cast stainless steel fittings. The analysis is consistent with the criteria specified in NUREG-1061 Volume 3, using the modified limit load method as specified in the SRP, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which LBB crack stability evaluations were made. Through-wall flaw sizes were identified which would cause a leak at a rate of ten times the leakage detection subsystem capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, by analyzing plant-specific transients and cycles, the fatigue crack growth for the 40 years was shown to be acceptable for the accumulator injection line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The applicant stated that the accumulator injection line LBB analysis was further evaluated to determine the impacts of uprated power conditions and a 60-year operating period. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast piping fittings contained in the piping system, therefore, thermal aging is not an issue for the period of extended operation. Thermal aging of the stainless steel weld material was considered with saturated conditions (fully aged) and, therefore, is valid for the period of extended operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis. The impacts of changes in NSSS design conditions, and the 60-year operating period were determined to be negligible. The applicant stated that the conclusions of the original LBB analysis, contained in WCAP-15107-P-A, remained unchanged.

The accumulator injection line LBB analysis was evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The applicant concluded that the dynamic effects of accumulator injection line pipe breaks need not be considered in the structural design basis of Units 1 and 2 for the license renewal operating period.

4.4.6.2 Staff Evaluation

LBB analysis for Units 1 and 2, WCAP-15107-P-A, was revised to include the staff's SER, dated November 7, 2000, which approved the LBB for a 40-year operating period. WCAP-15107-P-A documents accumulator injection line piping geometry, loading, and material properties used in the fracture mechanics evaluation. It was indicated that there are no CASS fittings in the accumulator injection lines; therefore, thermal aging of these components is not a concern for the 60-year operating period.

Critical locations were identified and LBB crack stability evaluations were performed based on loading, pipe geometry, and fracture toughness considerations. Based on the evaluations, the resultant through-wall cracks offered leak rates sufficiently large to be detected by the plant's leakage detection system without pipe breakage.

Assessments of plant-specific transients and cycles determined that the fatigue crack growth for the 40-year operating period is acceptable for the accumulator injection line piping and that all margins are satisfied for the 40-year operating period. Furthermore, the LBB analyses were evaluated considering the effects of power uprate and a 60-year operating period.

It was demonstrated that transients and cycles for the 60-year period were bounded by the LBB analysis of the 40-year period and that there were no design changes due to the power uprate. The staff concluded that pursuant to 10 CFR 54.21(c)(1)(i), the applicant demonstrated that the existing analyses are valid for the period of extended operation, and are therefore, acceptable.

4.4.6.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 FSAR supplement summary description of Class 1 accumulator injection line piping LBB in LRA Section A15.4.3. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on Class 1 accumulator injection line piping LBB and, is therefore, acceptable.

4.4.6.4 Conclusion

The staff reviewed the applicant's TLAA on Class 1 accumulator injection line piping LBB, as summarized in LRA Section 4.4.6, and determined that the fracture mechanics analyses at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for Class 1 accumulator injection line piping LBB complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(i), 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 FSAR supplement contains an appropriate summary description of the TLAA on Class 1 accumulator injection line piping LBB for the period of extended operation, as required by 10 CFR 54.21(d).

4.4.7 Class 1 RHR Line Piping Leak-Before-Break Analysis

4.4.7.1 Summary of Technical Information in the Application

The applicant stated that the LBB analysis for Units 1 and 2 RHR suction line piping was performed in 1998. The results of the analysis are documented in WCAP-15105. The applicant stated that the report demonstrates compliance with LBB technology for the RHR line piping based on plant-specific analysis. Westinghouse revised WCAP-15105 to include the NRC safety evaluation approving the LBB analysis for the Units 1 and 2 RHR line piping in 2001. This revision is documented in WCAP-15105-P-A, Revision 1. The RHR line LBB analysis includes the effects of thermal stratification. The RHR line LBB analysis incorporates analysis parameters associated with original licensed power conditions and a 40-year operating period. WCAP-15105-P-A documents the plant-specific RHR line piping geometry, loading, and material properties used in the fracture mechanics evaluation. The applicant stated that the RHR line piping does not include cast stainless steel fittings.

The applicant stated that the analysis is consistent with the criteria specified in NUREG-1061 Volume 3, using the modified limit-load method as specified in the draft SRP, Section 3.6.3. Based on loading, pipe geometry, and fracture toughness considerations, enveloping critical locations were determined at which LBB crack stability evaluations were made. Through-wall flaw sizes were identified which would cause a leak at a rate of ten times the leakage detection subsystem capability of the plant. Large margins for such flaw sizes were demonstrated against flaw instability. Finally, by analyzing plant-specific transients and cycles, the fatigue crack growth for the 40 years was shown to be acceptable for the RHR line piping. All the recommended LBB margins (margin on leak rate, margin on flaw size, and margin on loads) were satisfied.

The applicant stated that the RHR line LBB analysis was further evaluated to determine the impacts of uprated power conditions and a 60-year operating period. The changes in the NSSS design conditions due to power uprate did not result in any changes to the piping loads used in the analysis. There are no cast piping fittings contained in the piping system; therefore, thermal aging is not an issue for the extended operating period according to the applicant. Thermal aging of the stainless steel weld material was considered with saturated conditions (fully aged) and, therefore, is valid for the period of extended operation. The transients and cycles for the 60-year operating period are the same as the transients and cycles used in the 40-year operating period analysis.

The impacts of changes in NSSS design conditions and the 60-year operating period were determined to be negligible. The conclusions of the original LBB analysis, contained in WCAP-15105-P-A, remained unchanged. The applicant stated that the RHR line LBB analysis was evaluated and determined to remain valid for the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i). The applicant concluded that dynamic effects of RHR suction line pipe breaks need not be considered in the structural design basis of Units 1 and 2 for the license renewal operating period.

4.4.7.2 Staff Evaluation

LBB analysis for the Units 1 and 2, WCAP-15105-P-A, was revised to include the staff's safety evaluation, dated December 18, 2000, which approved the LBB for a 40-year operating period. WCAP-15105-P-A, Revision 1, documents Class 1 RHR line piping geometry, loading, and material properties used in the fracture mechanics evaluation. The applicant stated that there are no CASS fittings in the RHR lines; therefore, the staff agreed that thermal aging of these components is not a concern for the 60-year operating period.

Critical locations were identified and LBB crack stability evaluations were performed based on loading, pipe geometry, and fracture toughness considerations. Based on the evaluations, the resultant through-wall cracks offered leak rates sufficiently large enough to be detected by the plant's leakage detection system without pipe breakage.

Assessments of plant cycles and transients demonstrate that the fatigue crack growth for the 40-year operating period is acceptable for the RHR suction line piping and that all margins are satisfied for the 40-year period. In addition, LBB analyses were evaluated considering the effects of power uprate and a 60-year operating period.

The RHR suction line has no CASS components; therefore, the effects of thermal aging are not a concern. It was determined that transients and cycles for the 60-year period were bounded by the LBB analysis of the 40-year period and that there were no design changes due to the power uprate. The staff concluded that pursuant to 10 CFR 54.21(c)(1)(i), the applicant demonstrated that the existing analyses are valid for the period of extended operation, and are therefore, acceptable.

4.4.7.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 FSAR supplement summary description of RHR line piping LBB in LRA Section A15.4.3. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on RHR line piping LBB and, is therefore, acceptable.

4.4.7.4 Conclusion

The staff reviewed the applicant's TLAA on RHR line piping LBB, as summarized in LRA Section 4.4.7, and determined that the fracture mechanics analyses at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for RHR line piping LBB complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(i), 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 FSAR supplement contains an appropriate summary description of the TLAA on RHR line piping LBB for the period of extended operation, as required by 10 CFR 54.21(d).

4.4.8 Component / Piping Subsurface Indication Analysis

4.4.8.1 Summary of Technical Information in the Application

In LRA Section 4.4.8, the applicant stated that fracture mechanics analyses of RV nozzle flaws were used to justify continued serviceability of the Unit 1 RV. The fracture mechanics methodology was invoked to justify continued serviceability for approximately a 10-year period. With improvements in NDE equipment and techniques, the RV nozzle indications were subsequently identified to be within ASME Code allowable limits, and directly acceptable. Therefore, the applicant concluded that PBNP does not have any active TLAAs associated with component/piping subsurface indications.

4.4.8.2 Staff Evaluation

In LRA Section 4.4.8, the applicant stated that there are no active TLAAs associated with component/piping subsurface indications. Subsequently, in a letter dated March 4, 2005, the applicant deleted LRA Section 4.4.8.

4.4.8.3 FSAR Supplement

Component/piping subsurface indications are not identified as a TLAA, therefore, an FSAR supplement is not required. The applicant deleted LRA Section 4.4.8.

4.4.8.4 Conclusion

Component/piping subsurface indications do not have active TLAAs. The staff agreed with the applicant that component/piping subsurface indication analysis is not identified as a TLAA, in accordance with the definitions of 10 CFR 54.3. Furthermore, the applicant deleted LRA Section 4.4.8.

4.4.9 Reactor Vessel Head Penetration Analysis

4.4.9.1 Summary of Technical Information in the Application

As part of a review of changes in the CLB, the applicant identified the need of a new TLAA. By letter, dated February 23, 2005, the applicant added LRA Section 4.4.9, Reactor Vessel Head Penetration Analysis.

In LRA Section 4.4.9, the applicant stated that additional structural, fatigue, corrosion, and fracture mechanics analyses have been performed to support the inspections of both Units 1 and 2 RPV heads Alloy 600 penetrations and inspection and repair of the Unit 1 RPV head penetration No. 26. The applicant stated that the results of the analyses indicated that continued operation of the RPV heads can only be justified through the current operating cycle due to Alloy 600 penetrations. The RPV heads will be replaced with new heads that do not incorporate Alloy 600 penetration material. The RPV heads will be replaced during each unit's respective 2005 outage. The applicant stated that all analyses associated with the new RPV heads have been evaluated for operation for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

4.4.9.2 Staff Evaluation

Based on the information provided by the applicant, the structural, fatigue, corrosion, and fracture mechanics analyses of the RPV heads meet the definition of TLAA as defined under 10 CFR 54.3(a). The RPV heads are within the scope of systems, structures, and components in accordance with 10 CFR 54.4, specifically annotated under the integrity of the reactor coolant pressure boundary. The staff agreed that with its RPV heads currently in service, the TLAA does not support continued operation pursuant to 10 CFR 54.21(c)(1)(i) and (ii) due to Alloy 600 weld penetration cracking.

The applicant stated that the RPV head for each unit is scheduled for replacement in the 2005 outages. Material and design enhancements are being incorporated into the replacement heads to enhance the corrosion resistance of the head penetration assemblies. Other design enhancements are being incorporated to aid in disassembly/assembly efficiency. Some of the enhancements include elimination of Alloy 600 materials, elimination of unnecessary spare head penetrations, elimination of unnecessary joints in the CRDM housings, and an improved penetration weld joint design. The applicant stated that the replacement heads are being designed and manufactured to ASME Section III, 1998 Edition through 2000 Addenda. Design specification for the replacement RPV heads states that the components are designed to have a 40-year design life. The design specification for the replacement RPV heads specify the same design transient set that was used in the Steam Generator Replacement and Power Uprate projects for extended EOL conditions. The conclusion was that when the replacement components are placed into service, the 40-year design life is adequate to reach the extended EOL. The analyses associated with verifying the structural integrity of the reactor vessel heads have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(i).

The applicant's commitment to replace the RPV heads with heads having penetrations welded with Alloy 690 material is consistent with the industry practice acceptable by the staff. In its letter, dated January 25, 2005, the applicant stated that the RPV heads will be replaced during each unit's upcoming refueling outages. Furthermore, the applicant stated that the replaced RPV heads will be inspected in accordance with the requirements of NRC Order EA-03-009, "Order Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," revised on February 20, 2004. Finally, the applicant stated that NMC is actively participating with the industry through the EPRI MRP efforts to develop long-term inspection requirements for reactor vessel closure heads and their penetrations for U.S. PWR plants. The staff concluded that the replacement of the RPV heads along with the commitment to monitor the new heads in accordance with the most recent MRP guidelines and the first revised Order EA-03-009 provides the most conservative and up-to-date methodology for inspecting PWSCC in CRDM penetrations.

In its letter, dated January 25, 2005, the applicant committed to use the interim report "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plant (MRP-44), Part 1: Alloy 82/182 Pipe Butt Welds," and its final version, as part of the basis for the Reactor Coolant System Alloy 600 Inspection Program. The applicant also committed to submit the Reactor Coolant System Alloy 600 Inspection Program to the NRC for staff review and approval 24 to 36 months prior to the period of extended operation. The Reactor Coolant System Alloy 600 Inspection Program is evaluated in SER Section 3.0.3.2.15. Based on the discussion above, the applicant demonstrated that an aging management program will be in effect to monitor the effects of aging on the replacement heads for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.4.9.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement description of the reactor vessel head penetration analysis in LRA Section A15.4.3, as modified by letter dated August 23, 2005. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on reactor vessel head penetration analysis and, is therefore, acceptable.

4.4.9.4 Conclusion

The staff reviewed the applicant's TLAA on reactor vessel head penetration analysis, as summarized in LRA Section 4.4.9, and determined that the fracture mechanics analyses at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for the reactor vessel head penetration analysis complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(i) and (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 FSAR supplement contains an appropriate summary description of the TLAA on reactor vessel head penetration analysis for the period of extended operation, as required by 10 CFR 54.21(d).

4.5 Loss of Preload

4.5.1 Containment Tendon Loss of Prestress Analysis

4.5.1.1 Summary of Technical Information in the Application

The Units 1 and 2 containment buildings are post-tensioned, reinforced concrete structures composed of vertical cylinder walls and a shallow dome, supported on a conventional reinforced concrete base slab. The cylinder walls are provided with vertical tendons and horizontal hoop tendons. The dome is provided with three groups of tendons oriented 120 degrees apart.

In the LRA, the applicant described the factors it considered for estimating the final prestress forces in tendons, and how they were utilized in designing the containments. The applicant also summarized the method by which it established the upper and lower limits for each group of tendons in the two containments. Based on the applicant's projections of the tendon forces at the end of the period of extended operation, the predicted final effective preload at the end of 60 years exceeds the minimum required preload for all containment tendons. Consequently, the post-tensioning subsystem will continue to perform its intended function throughout the period of extended operation.

Furthermore, the applicant stated that the analyses associated with containment tendon loss of prestress have been projected to the end of the period of extended operation, in accordance with the requirements of 10 CFR 54.21(c)(1)(ii).

In the LRA, the applicant stated that as a confirmatory measure, the containment structure post-tensioning subsystem surveillances will continue to be performed in accordance with the Pre-Stressed Concrete Containment Tendon Surveillance Program to verify the integrity of the tendons. In a letter, dated February 23, 2005, the applicant withdrew this program and deleted LRA Sections A15.3.1 and B3.3.

4.5.1.2 Staff Evaluation

In addition to the analysis results summarized in this TLAA, the staff reviewed applicable aspects of LRA Section B2.1.2, ASME Section XI, Subsections IWE and IWL Inservice Inspection Program

The staff's review of LRA Section 4.5.1 identified areas requiring additional information to complete the review of the containment tendon loss of prestress evaluation. The applicant responded to the staff's RAIs as discussed below.

RAI 4.5-1. The use of 10 CFR 54.21(c)(1)(ii) and (iii) is appropriate for concrete containment tendon prestress TLAA. However, the staff determined that it needed to assess the plant-specific operating experience regarding the residual prestressing forces in the containments, and the methods used to arrive at the projected prestresses forces. Based on the analysis performed pursuant to 10 CFR 54.21(c)(1)(ii), in RAI 4.5-1, dated July 27, 2004, the staff requested the applicant to provide the following:

(1) The estimated upper and lower bound lines, and the minimum required prestressing forces for each group of tendons for each containment.

(2) Trend lines of the projected prestressing forces for each group of tendons based on the regression analysis of the measured prestressing forces. Also, the actual measured prestressing forces that were used to obtain the trend lines.

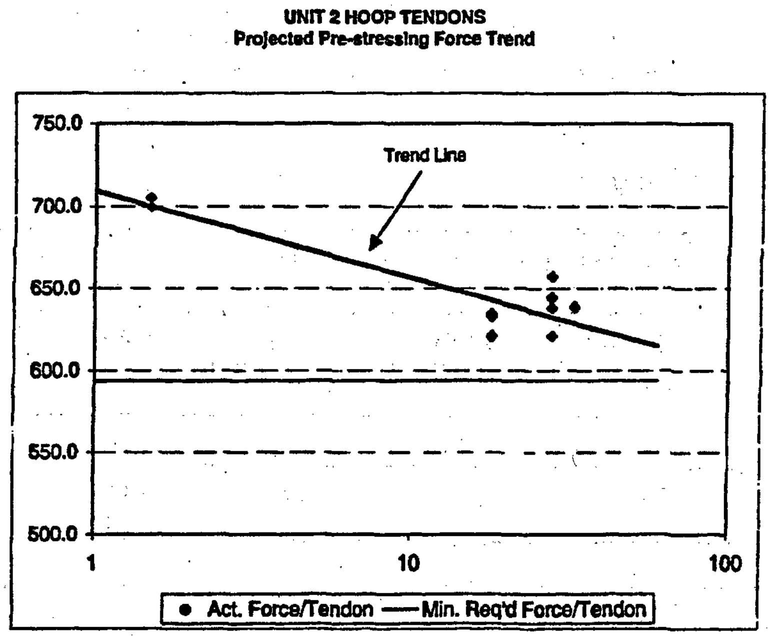
(3) Plots showing comparisons of prestressing forces projected to 40 years and 60 years with the minimum required prestress (or MRV) for each group of tendons for each containment.

In its response, dated August 26, 2004, the applicant provided a set of tendon prestressing plots that have been developed in accordance with RG 1.35.1 (reference Calculation 2000-0056, Tendon Prestress Acceptance Limits, Rev. 0). The plots for 60 years include the upper and lower bound lines and the minimum required prestressing force for each group of tendons for each of the containments per RG 1.35.1.

In response to RAI 4.5-1 items (2) and (3), the applicant provided the prestressing force plots with the trend lines of the projected prestressing forces for each group of tendons out to 60 years. The initial plots attached to LRA Section 4.5 were based on the lift-off testing of common tendons. This approach was not acceptable, as it was based on measurements of one tendon in a group. The staff recommended that the applicant develop the trend lines from all measured lift-off data, using a linear regression analysis. The applicant developed the trend lines using linear regression analysis and utilizing all measured lift-off force data. In its response, the applicant noted that this trend line information was based on draft calculations, and that the information will be resubmitted; if the final approved calculation revealed a different conclusion.

During a meeting on February 15, 2005, the staff indicated and the applicant agreed, that this response required further clarification. In its response, a clarification letter dated March 15, 2005, the applicant provided the corrected final plots showing the trend lines and the actual measured prestressing forces. Figure 4.5-1, shows a plot for Unit 2 hoop tendon reproduced for illustration purposes.

Figure 4.5-1 Unit 2 Hoop Tendons, Projected Prestressing Force Trend



The staff found the process used in arriving at the tend lines to be in conformance with the provisions of NUREG-1800 Section 4.5.3.1.2 and, therefore, it is acceptable. The staff recognizes that the slopes of the trend lines could change as a result of the prestressing tendon measurements taken during future inspections. However, the applicant will evaluate the results pursuant to IWL-3221.1(c), and take corrective actions as stipulated in the LRA. The staff's concerns described in RAI 4.5-1 are resolved.

RAI 4.5-2. In LRA Section A15.3.1, the applicant summarized the Prestressed Concrete Containment Tendon Surveillance Program, as an activity related to this TLAA. The applicant's description was qualitative. For the summary to be meaningful, at a minimum, the staff determined that the applicant should provide a Table showing the minimum required prestressing forces and the projected (to 60 years) prestressing forces for each group of tendons which would demonstrate the validity of the program and the corresponding TLAA results. In RAI 4.5-2, dated July 27, 2004, the staff requested the applicant to provide this information to supplement LRA Section A15.3.1.

In its response, dated August 26, 2004, the applicant stated that the minimum required prestressing forces were interpreted to mean the "final effective stress" at 60 years as discussed in the FSAR. The final effective stress was chosen to be the same value for 40 or 60 years. In a tabular form, the applicant provided the projected prestressing forces for each group of tendons in each Unit, together with the corresponding minimum required prestressing forces, as stipulated in FSAR Section 5.1.2.4. As the minimum required prestressing forces are stated in the plant FSAR, the applicant pointed out that they were not needed in LRA Section A15.3.1.

During a meeting on February 15, 2005, the staff indicated and the applicant agreed, that this response required further clarification. The applicant was requested to present the projected prestressing forces at 40 and 60 years, along with the minimum required force. In its response, a clarification letter dated March 15, 2005, the applicant provided the results of its finalized calculations and the per tendon information. Table 4.5-1 reflects the applicant's projected prestressing forces.

Table 4.5-1 Projected Prestressing Forces

Unit	Trend Line Values in kips/tendon 40 years			Trend Line Values in kips/tendon 60 years		
	Dome	Hoop	Vertical	Dome	Hoop	Vertical
1	634.3	637.9	661.6	629.4	634.1	658
2	620.5	624.3	640.9	612	615	634.3
Minimum Required Force	607	594.2	621.2	607	594.2	621.2

By letter dated February 23, 2005, the applicant withdrew LRA Section B3.3, "Pre-Stressed Concrete Containment Tendon Surveillance Program," and LRA Section A15.3.1. The staff found the applicant's approach acceptable, as it provides the necessary description in the existing FSAR. The staff's concern described in RAI 4.5-2 is resolved.

4.5.1.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of the containment tendon loss of prestress analysis in LRA Section A15.4.4. On the basis of its review, the staff concluded that the FSAR supplement summary adequately describes the TLAA on containment tendon loss of prestress analysis and, is therefore, acceptable.

4.5.1.4 Conclusion

The staff reviewed the applicant's TLAA on containment tendon loss of prestress analysis, as summarized in LRA Section 4.5.1, and determined that the loss of preload analyses at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for containment tendon loss of prestress analysis, complies with the staff's acceptance criterion for TLAAs in 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 FSAR supplement contains an appropriate summary description of the TLAA on containment tendon loss of prestress analysis for the period of extended operation, as required by 10 CFR 54.21(d).

4.6 Neutron Absorber

4.6.1 Spent Fuel Pool Storage Rack Boraflex

4.6.1.1 Summary of Technical Information in the Application

The application of the neutron absorber (Boraflex) in the spent fuel pool (SFP) storage racks is based on degradation studies that assume an integrated dose expected during service for 40 years. Therefore, Boraflex is defined as a TLAA in accordance with 10 CFR 54.21(a)(3). The applicant credits the Boraflex Monitoring Program with providing reasonable assurance that aging effects associated with Boraflex will be adequately managed for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

Currently, the Boraflex Monitoring Program consists of blackness testing conducted once every 5 years and SFP silica level measurements taken monthly in accordance with plant procedures. In addition, criticality monitoring by analyses are performed to assure the 5-percent subcriticality margin requirement is maintained. Prior to the period of extended operation, this program will be enhanced to include areal density testing, blackness testing or neutron attenuation, and SFP silica level tracking as qualitative indicators of Boraflex degradation. The applicant will also continue to perform criticality monitoring by analyses. These enhancements will ensure the Boraflex Monitoring Program will be consistent with the GALL Report.

Blackness tests are used to determine gap formation, distribution, and size. Areal density tests are conducted to determine the physical loss of boron carbide (*e.g.*, wall thickness), while SFP silica levels are measured as a qualitative indication of boron carbide loss. Blackness and areal density test results are used to determine the Boraflex integrity in the SFP racks. The results of the areal density tests and SFP silica level measurements are used to verify the SFP rack design basis is being maintained.

4.6.1.2 Staff Evaluation

The staff's review of LRA Section 4.6.1 identified areas requiring additional information to complete the review of the SFP rack Boraflex evaluation. The applicant responded to the staff's RAIs as discussed below.

Consistent with 10 CFR 50.21(c)(1)(iii), the applicant proposes to manage the aging effects associated with the Boraflex through an aging management program. The applicant proposes to credit the Boraflex Monitoring Program, which requires that 10 full-length Watcher-designed Boraflex panels be tested during each surveillance. The Boraflex panels have been exposed to the greatest number of freshly discharged fuel assemblies and consist of four panels with accelerated exposure and six randomly selected panels. The same four panels with accelerated exposure are tested during each scheduled surveillance.

Currently, scheduled surveillances are conducted once every 5 years and include blackness tests and SFP silica level measurements. During the period of extended operation, the applicant committed to enhance the program to be consistent with NUREG-1801 (*i.e.*, areal density tests, blackness tests or neutron attenuation, SFP silica level measurements, and criticality monitoring by analysis).

RAI 4.6.1-1. The surveillance frequency of once every 5 years for the blackness testing was approved in an NRC letter dated February 21, 1990. Based on industry operating experience indicating the varying degree to which the Boraflex panels degrade, the staff requested a justification for continuing the 5-year frequency for areal density testing into the period of extended operation. In RAI 4.6.1-1, dated March 29, 2005, the staff requested the applicant to provide the most recent blackness test and SFP silica level measurements, and use this data to demonstrate the current rate of degradation will not exceed the acceptance criteria.

During conversations with the staff, the applicant committed to enhance the Boraflex Monitoring Program. In addition, the applicant agreed to provide the requested data to the Region III staff for their review at their AMR/AMP onsite inspection during the weeks of March 7 and 21, 2005. The applicant's data and the Boraflex Monitoring Program enhancements are expected to ensure that the neutron absorbing material will continue to perform its intended function during the period of extended operation. This was identified as confirmatory item (CI) 4.6.1-1.1.

The staff also requested the applicant provide justification for the 5-year frequency for areal density testing. During conversations with the staff, the applicant committed to perform areal density and blackness tests on certain accelerated Boraflex panels once every 2 years during the period of extended operation. This was identified as confirmatory item (CI) 4.6.1-1.2.

In response to CIs 4.6.1-1.1 and 4.6.1-1.2, by letter dated April 1, 2005, the applicant committed to create a new procedure to schedule and perform blackness testing and areal density testing every 2-years during the period of extended operation on certain accelerated Boraflex panels. These actions are consistent with the recommendations in the August 2001 Boraflex degradation analyses reviewed by the Region III staff during the March 2005 inspection and as documented in its inspection report dated May 2, 2005. The staff found the applicant's response to RAI 4.6.1-1 and its commitment acceptable because these actions ensure that the neutron absorbing material will continue to perform its intended function in maintaining SFP subcriticality. The staff's concerns are resolved; and therefore, CIs 4.6.1-1.1 and 4.6.1-1.2 are closed.

RAI 4.6.1-2. The applicant indicated that a predictive code, "EPRI RACKLIFE or its equivalent," will be used to determine which panels will be subjected to full-length testing (*i.e.*, blackness testing, neutron attenuation, and areal density testing) and to trend and analyze SFP silica level measurement results. The input to the predictive code includes areal density and SFP silica level measurements. The staff is unclear on the ability of the predictive code to project panel degradation if the first areal density test is completed after the beginning of the period of extended operation. Therefore, in RAI 4.6.1-2, dated March 29, 2005, the staff requested the applicant to provide justification regarding the ability of the predictive code to accurately project the condition of the panels to ensure the degradation does not exceed the acceptance criteria with one set of data. In addition, if this justification cannot be made, the staff requested the applicant commit to conducting a baseline areal density test prior to entering the period of extended operation.

During conversations with the staff, the applicant committed to perform a baseline areal density inspection of the Boraflex panels prior to entering the period of extended operation for predictive code purposes. The applicant will revise its response to reflect this statement. This was identified as confirmatory item (CI) 4.6.1-2.

In its response to CI 4.6.1-2, by letter dated April 1, 2005, the applicant committed to perform a baseline areal density inspection of the Boraflex panels prior to entering the period of extended operation to support the use of a predictive code for projecting the condition of the panels between surveillance tests. In addition, the applicant committed to perform an evaluation within its corrective action program should silica sampling and areal density trend to a value less than the acceptance criteria. The corrective actions also include an increase in the frequency of blackness testing and areal density testing. The staff found the applicant's response to RAI 4.6.1-2 and its associated commitments acceptable because these actions ensure that the predictive code will have the appropriate data for projecting the degradation of Boraflex into the period of extended operation without exceeding the acceptance criteria. The staff's concern is resolved and, therefore, CI 4.6.1-2 is closed.

RAI 4.6.1-3. For the acceptance criteria element, the applicant states that this element is consistent with NUREG-1801. The applicant committed to making appropriate changes to the program if any of the test results indicate that program improvements should be made. However, the staff found this discussion insufficient for ensuring adequate management of Boraflex degradation. In RAI 4.6.1-3, dated March 29, 2005, the staff requested the applicant to provide more information regarding the Boraflex Monitoring Program's acceptance criteria (*i.e.*, when the number of panels to be inspected should be expanded and when the surveillance frequency should be decreased). Additionally, the staff requested the applicant to provide a discussion regarding what specific corrective actions will be taken if trends indicate the acceptance criteria may not be met.

During conversations with the staff, the applicant committed to complete an evaluation, within its corrective action program, and increase the frequency of blackness and areal density testing if the silica sample and the areal density trend to a value less than the acceptance criteria. The applicant committed to provide specific details of the corrective actions that will take place if the acceptance criteria cannot be maintained. The applicant's enhancements to the program and corrective actions are expected to ensure continued material performance. The applicant will revise its response to reflect these statements. This was identified as confirmatory item (CI) 4.6.1-3.

In response to CI 4.6.1-3, by letter dated April 1, 2005, the applicant committed to complete an evaluation within its corrective action program if silica sampling and areal density trend to a value less than the acceptance criteria. In addition, the frequency of blackness testing and areal density testing will be increased. Specifically, corrective actions will be initiated if the test results find that the 5-percent subcriticality margin cannot be maintained because of current or projected future Boraflex degradation. These corrective actions may include, but are not limited to, reanalysis, and repair and/or replacement of the neutron absorbing material. The staff found the applicant's response to RAI 4.6.1-3 acceptable because the corrective actions ensure continued material performance, consistent with the acceptance criteria, into the period of extended operation. The staff's concerns are resolved and, therefore, CI 4.6.1-3 is closed.

The staff concluded that there is reasonable assurance that the Boraflex Monitoring Program credited by the Neutron Absorber TLAA, with the stated enhancements and commitments, will adequately manage the aging effects of the Boraflex panels in the SFP racks in accordance with the CLB during the period of extended operation.

4.6.1.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR 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 an FSAR supplement summary description of SFP storage rack Boraflex in LRA Section A15.4.5. On the basis of its review, the staff concluded the FSAR supplement summary adequately describes the TLAA on SFP storage rack Boraflex and, is therefore, acceptable.

4.6.1.4 Conclusion

The staff reviewed the applicant's TLAA on SFP pool storage rack Boraflex, as summarized in LRA Section 4.6, and determined the neutron absorber at Units 1 and 2 will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded that the applicant's TLAA for SFP storage rack Boraflex complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(iii), and 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 the FSAR supplement contains an appropriate summary description of the TLAA on SFP storage rack Boraflex for the period of extended operation, as required by 10 CFR 54.21(d).

4.7 Wear

4.7.1 Bottom Mounted Instrumentation Thimble Tube Wear

4.7.1.1 Summary of Technical Information in the Application

LRA Section 4.7.1 states that IN 87-44, Supplement 1, "Thimble Tube Thinning in Westinghouse Reactors," thimble tubes have experienced thinning as a result of flow-induced vibration. Thimble tube wear degrades the reactor coolant system pressure boundary and could create a non-isolable leak of reactor coolant. Therefore, the staff requested that licensees perform the actions described in NRC Bulletin No. 88-09, "Thimble Tube Thinning in Westinghouse Reactors." In response to this bulletin, PBNP established a program for inspection and assessment of thimble tube thinning, which was accepted by NRC in a letter to Wisconsin Electric dated November 22, 1989.

The applicant stated that the original thimble tubes for both Units were replaced during the 1984 -1985 time frame. It was necessary to replace these tubes due to internal blockages and deposits. Subsequent to the original replacement, five Unit 1 thimble tubes were replaced due to vibration damage. No through wall in-core thimble tube leakage has ever been experienced at PBNP.

The thimble tubes are inspected in accordance with the Thimble Tube Inspection Program. The program determines the frequency of inspection by calculating wear rates based on historical inspection data. Any tubes determined to be below acceptance criteria as projected to the next inspection period are repositioned, replaced, or plugged. The Thimble Tube Inspection Program is described in LRA Section B2.1.23.

The thimble tubes have proven to be short-lived components that are replaceable on condition. The Thimble Tube Inspection Program is designed to adequately monitor thimble tube condition to ensure that the thimble tubes are capable of performing their intended function. The applicant concluded that thimble tube wear is not a TLAA.

4.7.1.2 Staff Evaluation

LRA Section 4.7.1 states that thimble tubes are short-lived and are replaceable on condition. The staff agreed with the applicant that thimble tube wear is not a TLAA. However, the applicant credits the Thimble Tube Inspection Program to monitor thimble tube condition to ensure they perform their intended function. The staff's evaluation of the Thimble Tube Inspection Program is documented in SER Section 3.0.3.3.4.

4.7.1.3 FSAR Supplement

Thimble tube wear is not identified as a TLAA, therefore, an FSAR supplement is not required.

4.7.1.4 Conclusion

Thimble tubes are short-lived components that are replaceable on condition. The staff agreed with the applicant that thimble tube wear is not an applicable TLAA.

4.7.2 Containment Accident Recirculation Heat Exchanger Tube Wear

4.7.2.1 Summary of Technical Information in the Application

LRA Section 4.7.2, states that PBNP has not experienced containment accident recirculation fan heat exchanger tube wear. In addition, there are no specific design analyses of vibration and/or fatigue associated with the containment accident recirculation fan heat exchangers. Therefore, the applicant concluded that the containment accident recirculation heat exchanger tube wear is not a TLAA.

4.7.2.2 Staff Evaluation

LRA Section 4.7.2, stated that the containment accident recirculation heat exchanger tube wear is not a TLAA. Subsequently, by letter dated March 4, 2005, the applicant deleted LRA Section 4.7.2.

4.7.2.3 FSAR Supplement

Containment accident recirculation heat exchanger tube wear is not identified as a TLAA, therefore, an FSAR supplement is not required. Furthermore, the applicant deleted LRA Section 4.7.2.

4.7.2.4 Conclusion

PBNP has not experienced containment accident recirculation heat exchanger tube wear. The staff agreed with the applicant that containment accident recirculation heat exchanger tube wear is not an applicable TLAA. Furthermore, the applicant deleted LRA Section 4.7.2.

4.8 <u>Environmental Qualification</u>

The 10 CFR 50.49 environmental qualification (EQ) program was identified as a TLAA for the purpose 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. Harsh environments within the plant are defined as areas that are subjected to environmental effects by a loss-of-coolant accident (LOCA) or a high-energy line break (HELB). The EQ equipment comprises safety-related and Q-list equipment; nonsafety-related equipment for which the failure could prevent satisfactory accomplishment of any safety-related function; and the necessary post-accident monitoring equipment.

As required by 10 CFR 54.21(c)(1), the applicant is to provide a list of EQ TLAAs in the LRA. The applicant will demonstrate that one of the following is true for each type of EQ equipment:

- the analyses remain valid for the period of extended operation;
- the analyses were projected to the end of the period of extended operation; and
- the effect of aging on the intended function(s) will be adequately managed for the period of extended operation.

4.8.1 Environmental Qualification of Electrical Equipment

The staff established nuclear station EQ requirements in 10 CFR 50 Appendix A Criterion 4 and 10 CFR 50.49. Section 49 of 10 CFR, Part 50, specifically requires that an EQ program be established to demonstrate that certain electrical components located in "harsh" plant environments are qualified to perform their safety function in those environments after the effects of in-service aging. Harsh environments are defined as those areas of the plant that could be subject to the environmental effects of a LOCA, HELB, or post-LOCA radiation. The effects of significant aging mechanisms are required by 10 CFR 50.49 to be addressed as part of an EQ program. For the purpose of license renewal, only those components with a qualified life of 40 years or greater would be TLAAs.

The staff reviewed LRA Section 4.8 where the applicant described the technical bases and justification for its EQ program to adequately manage the effects of aging on the intended function(s) of electrical components for the period of extended operation. The staff reviewed this section to determine whether the applicant demonstrated the effects of aging on the intended function(s) of the electrical equipment will be adequately managed through the EQ program, together with other programs and processes, during the period of extended operation as required by 10 CFR 54.21(c)(1)(iii).

4.8.1.1 Summary of Technical Information in the Application

In LRA Section 4.8, the applicant stated that its EQ program was established to demonstrate that certain electrical components are qualified to perform safety functions in the harsh environment following a design-basis accident. Elements of the proof of qualification involve the original 40-year license period. Therefore, the qualification reports and calculations that comprise the EQ program meet the definition of a TLAA. In general, the applicant did not establish qualified lives for the components within the EQ program longer than the original 40-year license period.

Qualified service lives for the EQ components were established and are tracked to determine when a component is nearing the end of its service life. For those components that are nearing the end of their qualified service life, the EQ program has provisions for the components to be re-evaluated for longer service (*i.e.*, refurbished, requalified, or replaced). Therefore, the TLAAs will be managed by an aging management program (AMP) in accordance with 10 CFR 54.21(c)(1)(iii). The applicant also included a list of EQ packages in LRA Table 4.8-1.

The EQ program manages thermal, radiation, and cyclical aging of components through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods. As required by 10 CFR 50.49, EQ components not qualified for the current license term are to be refurbished, replaced, or have their qualification extended prior to reaching the aging limits established in the evaluation. Aging evaluations for EQ components that specify a qualification of at least 40 years are considered TLAAs for license renewal. The EQ program ensures these EQ components are maintained within the bounds of their qualification bases. All equipment qualification summary sheets (EQSS) in the EQ program are considered to be TLAAs for license renewal due to thermal, radiation, and/or cyclic aging, except for EQSS related to lubricants. Lubricants are periodically checked and replaced and, therefore, are not considered to be TLAAs.

The reanalysis of an aging evaluation may be performed to extend the qualification by reducing margin or excess conservatism incorporated in the prior evaluation. Reanalysis of an aging evaluation to extend the qualification of a component may be performed as the part of the EQ program. While a component life-limiting condition may be due to thermal, radiation, or cyclical aging, the vast majority of component aging limits are based on thermal conditions. Conservatism may exist in aging evaluation parameters, such as the assumed ambient temperature of the component, unrealistically low activation energy, or in the application of a component as de-energized instead of energized. As discussed below, the important attributes of reanalysis will include analytical methods, data collection and conservative reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met).

Analytical Methods. The analytical models used in the reanalysis of an aging evaluation are the same as those applied during the first evaluation. The applicant stated that the Arrhenius methodology is an acceptable thermal model for performing an aging evaluation. The analytical method used for a radiation aging evaluation involves a demonstration of 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. For cyclical aging, a similar approach may be used. Other models may be justified on a case-by-case basis.

Data Collection and Reduction Methods. Reducing excess conservatism in the component service conditions (*e.g.*, temperature, radiation, cycles) used in the prior aging evaluation is the chief method used for a reanalysis. Temperature data used in an aging evaluation are to be conservative and based on plant design temperatures or on actual plant temperature data. Plant temperature data can be obtained in several ways, including monitors used for technical specification compliance, other installed monitors, measurements made by plant operators during rounds, and temperature sensors on large motors (while the motor is not running). A representative number of temperature measurements are conservatively evaluated to establish the temperatures used in an aging evaluation. Plant temperature data may be used in an aging evaluation in different ways, such as: (1) directly applying the plant temperature data, or (2) using the plant temperature data to demonstrate conservatism when using plant design temperatures. Any changes to material activation energy values as part of a reanalysis are justified on a case-specific basis. Similar methods of reducing excess conservatism in the component service conditions from prior aging evaluations may be used for radiation and cyclical aging.

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

Acceptance Criteria and Corrective Actions. The reanalysis of an aging evaluation could extend the qualification of a component. If the qualification cannot be extended by reanalysis, the component is maintained, replaced, or requalified prior to exceeding the period for which the current qualification remains valid. A reanalysis is performed in a timely manner (*i.e.*, sufficient time must be available to maintain, replace, or requalify the component if the reanalysis is unsuccessful).

The Cable Condition Monitoring Program is a new program that was established specifically for license renewal. This program manages aging of conductor insulation materials on cables and connectors, and other electrical insulation materials that are installed in adverse localized environments caused by heat, radiation, or moisture. The program requires visual inspection of a representative sample of accessible electrical cables and connections in adverse localized environments once every 10 years for evidence of jacket surface degradation. The scope of this program includes accessible non-EQ electrical cables and connectors, including I&C circuit cables. Although the scope of this program is aimed at non-EQ electrical cables and connectors, it is equally applicable to EQ electrical cables, since no distinction is made as to whether the cables being inspected are EQ or non-EQ.

4.8.1.2 Staff Evaluation

The staff reviewed LRA Section 4.8 to determine whether the applicant submitted adequate information to meet the requirement of 10 CFR 54.21(c)(1). For the electrical equipment identified in the LRA Table 4.8-1, the applicant used 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate the aging effects of EQ equipment will be adequately managed during the period of extended operation. The staff reviewed the EQ program to determine whether it will assure the electrical and I&C components covered under this program will continue to perform their intended functions consistent with the CLB for the period of extended operation. The staff's evaluation of the components' qualification focused on how the EQ program manages aging effects to meet requirements delineated in 10 CFR 50.49.

The applicant's EQ 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 (*i.e.,* 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.

4.8.1.3 FSAR Supplement

As required by 10 CFR 54.21(d), applicants for license renewal must include an FSAR supplement summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. The applicant provided FSAR supplement summary description of EQ in LRA Section A15.4.6. On the basis of its review, the staff concluded the FSAR supplement summary adequately describes the TLAA on EQ and, is therefore, acceptable.

4.8.1.4 Conclusion

The staff reviewed the applicant's TLAA on EQ, as summarized in LRA Section 4.8, and determined the EQ analyses will continue to comply with the staff's requirements throughout the period of extended operation. The staff concluded the applicant's TLAA for EQ complies with the staff's acceptance criterion for TLAAs in 10 CFR 54.21(c)(1)(iii), and the safety margins established and maintained during the current operating term will be maintained during the period of extended operation. The staff also concluded the FSAR supplement contains an appropriate summary description of the TLAA on EQ for the period of extended operation, as required by 10 CFR 54.21(d).

4.9 Conclusion for Time-limited Aging Analyses

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analysis." On the basis of its review, the staff concluded that the applicant provided an adequate list of TLAAs, as defined in 10 CFR 54.3. Furthermore, the staff concluded 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) 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 FSAR supplement for the TLAAs and found that the FSAR supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concluded that the applicant is in compliance with 10 CFR 54.21(c)(2) in that no plant-specific exemptions are in effect that are based on TLAAs.

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 to comply with 10 CFR 54.29(a) are in accord with the Act and NRC regulations.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The NRC staff issued its safety evaluation report (SER) with open items (OIs) related to the renewal of operating licenses for Point Beach Nuclear Plant (PBNP), Units 1 and 2, on May 2, 2005. On May 31, 2005, the applicant presented its license renewal application (LRA), and the staff presented its review findings to the Advisory Committee on Reactor Safeguards (ACRS) Plant License Renewal Subcommittee. In addition, both the applicant and the staff also presented in front of the ACRS Full Committee during its 523rd meeting, held on June 1-3, 2005.

In its interim report, letter dated June 9, 2005, the ACRS presented its findings to Mr. Luis A. Reyes, NRC Executive Director for Operations. The staff responded to the ACRS's concerns by letter dated July 15, 2005. A copy of both letters is provided on the following pages of this SER.

The staff reviewed the applicant's comments on the SER with OIs and completed its review of the LRA. The staff's evaluation is documented in an SER that was issued by letter dated October 1, 2005.

During the 527th meeting of the ACRS, held on November 3-5, 2005, the Full Committee completed its review of the PBNP LRA and the staff's SER. The ACRS documented its findings in a letter to the Commission dated November 18, 2005. A copy of this letter is also provided on the following pages of this SER.

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June 9, 2005

Mr. Luis A. Reyes
Executive Director for Operations
U.S. Nuclear Regulatory Commission
Washington, DC 2005-0001

SUBJECT: INTERIM REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

Dear Mr. Reyes:

During the 523rd meeting of the Advisory Committee on Reactor Safeguards, June 1-3, 2005, we reviewed the license renewal application for the Point Beach Nuclear Plant (PBNP), Units 1 and 2, and the associated Safety Evaluation Report (SER) with open items prepared by the NRC staff. Our Plant License Renewal Subcommittee also reviewed this matter on May 31, 2005. During these reviews, we had the benefit of discussions with representatives of the NRC staff, including Region III personnel, and the Nuclear Management Company, LLC. We also had the benefit of the documents referenced.

We recognize that the license renewal rule does not include specific consideration of current operating performance. However, aspects of current performance may affect the development of license renewal programs and commitments as well as the effectiveness of the implemented programs.

The Confirmatory Action Letter (CAL) issued to the PBNP on April 21, 2004 will remain open until improvements are demonstrated in the areas of human performance, engineering design control, the engineering/operations interface, emergency preparedness, and the Corrective Action Program (CAP).

An adequate CAP is a key element in the successful implementation of the aging management programs critical to license renewal. A review of the events leading to the issuance of the CAL leads to the conclusion that the applicant's CAP has been in a degraded condition for a long time. The Region III staff stated that the problems are not in the design of the program but in its implementation. The inspections have also identified other weaknesses in the area of human performance. Errors in engineering calculations have been identified and are being corrected, but this work is not yet complete. These errors may have an impact on long-lived passive components.

It often takes a long time to successfully implement improvements in human performance, and we note that the current operating license for Unit 1 expires on October 5, 2010. The March 2, 2005 Annual Assessment Letter to the PBNP notes that some improvements in the human performance area have been observed. However, problems continue to be identified in the CAP, and the PBNP remains in the Multiple/Repetitive Degraded Cornerstone column of the Reactor Oversight Process Action Matrix. The resources needed to address the CAL compete with the effective development, tracking, and implementation of license renewal programs and commitments.

In support of its final SER, the staff normally audits and inspects only a fraction of the license renewal programs and commitments. In the case of the PBNP, the staff should take additional actions to increase confidence that the requirements of the license renewal rule have been met and that there is reasonable assurance that aging degradation can be adequately managed. These actions may include, for example, an expanded inspection of license renewal commitments and a focused review of the effectiveness of the CAP before the PBNP enters the period of extended operation. We would like to hear about such planned actions during our review of the final SER.

Sincerely,

/RA/

Graham B. Wallis
Chairman

References

(1) Nuclear Management Company, LLC, "Application for Renewed Operating Licenses Point Beach Nuclear Plant Units 1 & 2," February 2004
(2) U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2," May 2005
(3) Letter from J. Caldwell, Regional Administrator, to G. Van Middlesworth, Site Vice President, Point Beach Nuclear Plant, Nuclear Management Company, LLC, "Confirmatory Action Letter," April 21, 2004
(4) Letter from J. Caldwell, Regional Administrator, to D. Koehl, Site Vice President, Point Beach Nuclear Plant, Nuclear Management Company, LLC, "Annual Assessment Letter - Point Beach Nuclear Plant (Report 05000266/200501; 05000301/200501)," March 2, 2005
(5) Letter from J. Dyer, Regional Administrator, to M. Warner, Site Vice President, Kewaunee and Point Beach Nuclear Plants, Nuclear Management Company, LLC, "Point Beach Special Inspection - NRC Inspection Report 50-266/01-17(DRS); 50-301/01-17(DRS), Preliminary Red Finding," April 3, 2002 and Preliminary Red Finding - Auxiliary Feedwater Orifice Plugging Issue; NRC Inspection Report 50-266/02-15(DRP); 50-301/02-15(DRP)," April 2, 2003

(6) Letter from J. Caldwell, Regional Administrator, to A. Cayia, Site Vice President, Point Beach Nuclear Plant, Nuclear Management Company, LLC, "Point Beach Nuclear Plant, Units 1 and 2 Final Significance Determination for a Red Finding and Notice of Violation (NRC Inspection Report No. 50-266/02-15(DRP); 50-301/02-15(DRP))," December 11, 2003

(7) Letter from G. Van Middlesworth, Site Vice President, Point Beach Nuclear Plant, Nuclear Management Company, LLC, to U.S. Nuclear Regulatory Commission Document Control Desk, "Commitments in Response to 95003 Supplemental Inspection," March 22, 2004

(8) Pacific Northwest National Laboratory, "Audit and Review Report for Plant Aging Management Reviews and Programs, Point Beach Nuclear Plant Units 1 and 2," April 11, 2005

(9) U.S. Nuclear Regulatory Commission, "Point Beach Nuclear Plant, Units 1 and 2 NRC License Renewal Scoping, Screening, and Aging Management Inspection Report 05000266/2005005 (DRS); 05000301/2005005 (DRS)," May 2, 2005

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July 15, 2005

Dr. Graham B. Wallis, Chairman
Advisory Committee on Reactor Safeguards
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

SUBJECT: RESPONSE TO ADVISORY COMMITTEE ON REACTOR SAFEGUARDS INTERIM REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

Dear Dr. Wallis:

In your letter dated June 9, 2005, you summarized the results of the interim review by the Advisory Committee on Reactor Safeguards (ACRS) of the Nuclear Management Company's (NMC's) license renewal application for Point Beach Nuclear Plant (PBNP), Units 1 and 2, and the associated safety evaluation report (SER) with open items prepared by the U.S. Nuclear Regulatory Commission (NRC) staff. The Committee believes the staff should take additional actions to increase confidence that the requirements of the license renewal rule have been met and that there is reasonable assurance that aging degradation can be adequately managed.

As you recognize in your letter, the license renewal rule requires current performance issues to be addressed within the context of Title 10, Part 50, of the *Code of Federal Regulations* (10 CFR Part 50). Section 54.30(a) states that if there is not reasonable assurance during the current license term that licensed activities will be conducted in accordance with the current licensing basis (CLB), the licensee must take measures under its current license to ensure that intended functions will be maintained in accordance with the CLB throughout the term of its current license. Section 54.30(b) states that compliance with Section 54.30(a) is not within the scope of the license renewal review. Results from actions taken to resolve a current license problem becomes part of the CLB and will be carried forward into the period of extended operation. In the first quarter of 2003, PBNP entered the Multiple/Repetitive Degraded Cornerstone column of the Reactor Oversight Process (ROP) Action Matrix. NRC actions under the ROP are described in the enclosure to this letter.

With regard to the license renewal process, the staff's SER with open items issued on May 2, 2005, contains five open items. The open items are being resolved and will be documented in the final SER. During the past year, the staff has performed several onsite audits and inspections to ensure the applicant is addressing all items required by the license renewal rule. The NRC staff audited all aging management programs credited in the PBNP license renewal application. Additionally, the Region III staff performed its combined scoping, screening, and aging management inspection which identified no findings. During this effort, the Region III staff inspected 18 out of 26 aging management programs credited in the license renewal application. The remaining programs are evaluated through standard baseline inspections. The inspection team verified that the applicant meets the requirements of the license renewal rule and has implemented license renewal programs and activities consistent with its application. During this inspection, NMC was in the process of modifying the scoping methodology and expanding the non-safety-related component scope. Therefore, in

August 2005, the Region III staff will perform a followup inspection under Inspection Procedure (IP) 71002. This inspection will focus on the One-Time Inspection Program, non-safety-related component scoping, license renewal commitments, and recently implemented actions.

The staff understands the Committee's concern about NMC's ability to implement its aging management programs and LRA commitments. If the license is renewed, the staff will conduct License Renewal Application (LRA) post-approval site inspection for license renewal in accordance with IP 71003 before the period of extended operation begins. During this inspection the staff will verify: (1) that all license renewal programs and activities have been implemented in accordance with the license renewal rule, (2) that outstanding commitments have been met, and (3) that the FSAR supplement contains the required summary description of aging management programs and activities.

The staff recognizes the ACRS's commitment to safety and appreciates the Committee's continued efforts in support of the license renewal process.

Sincerely,

/RA/

Luis A. Reyes
Executive Director
for Operations

Enclosure: As stated

cc: Chairman Diaz
Commissioner Merrifield
Commissioner Jaczko
Commissioner Lyons
SECY

NRC ACTIONS UNDER THE REACTOR OVERSIGHT PROCESS FOR THE POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

In the first quarter of 2003, the Point Beach Nuclear Plant (PBNP), Units 1 and 2, entered the Multiple/Repetitive Degraded Cornerstone column (Column IV) of the Reactor Oversight Process (ROP) Action Matrix. The Region III staff conducted a three-phase supplemental inspection, in accordance with Inspection Procedure (IP) 95003, to review the licensee's corrective actions. As stated in the NRC confirmatory action letter (CAL) dated April 21, 2004, the NRC must determine that performance improvements have actually been made before closing the inspection findings. In making this determination the NRC has considered: (1) plant events and findings that may reveal similar performance weaknesses, (2) performance indicators, (3) the implementation of the licensee's performance improvement plan, and (4) the results of supplemental inspections. Nuclear Management Company (NMC) developed an improvement plan (entitled Excellence Plan) and submitted a commitment letter dated March 22, 2004, focusing on performance issues. NMC committed to make sustained improvement to address issues in: (1) human performance, (2) engineering design control, (3) the engineering/operations interface, (4) emergency preparedness, and (5) the corrective action program (CAP).

Since then, the Region III staff has been assessing and documenting PBNP's performance on a quarterly basis. In the first 2005 quarterly report, as in the annual assessment letter dated March 2, 2005, the Region III staff concluded that PBNP is operating in a manner that preserves the public health and safety. NMC has been providing its CAL action step completion reports to the NRC during periodic public meetings, and the Region III staff will continue to monitor improvement in all areas listed in the CAL. During June 2005, the Region III staff performed two CAL special inspections. These inspections evaluated the licensee's actions in the areas of human performance and emergency preparedness. The Region III staff will also perform two CAL special inspections in the next few months. A team inspection of engineering effectiveness and the engineering/operations interface will be conducted during the weeks of July 26, 2005 and August 8, 2005. An expanded problem identification and resolution (PI&R) inspection of the licensee's CAP will be conducted during the weeks of September 12, 2005 and September 26, 2005. Both inspection teams will include more inspectors than the standard baseline inspections and will be supplemented by inspectors from outside the region.

The Committee commented that an adequate CAP is a key element in the successful implementation of the aging management programs critical to license renewal. NRC has established measures to evaluate CAP effectiveness during biennial PI&R baseline inspections. Items entered in the licensee's CAP are reviewed daily by the resident inspectors and assessed for immediate or future followup and potential trends. For PBNP, in addition to the inspections described previously, the staff will perform at least two PI&R inspections (in CY07 and CY09) before the plant enters the period of extended operation. During these inspections, the staff will evaluate the licensee's ability to identify and correct problems, including those related to license renewal. Consistent with Inspection Manual Chapter (MC) 0305, after the original red findings have been closed out, the Region III office may take actions, such as periodic senior management site visits, to ensure appropriate oversight of the licensee's improvement initiatives. The MC prescribes up to 200 hours of direct inspection activity to review selected performance areas when the licensee has been removed from Column IV. Once this happens, the Region III staff plans to expend at least 100 hours of that allowance on special reviews of the licensee's CAP. Although problems have been identified in the licensee's CAP, inspections to date have shown that the licensee's program is adequate.

ENCLOSURE

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November 18, 2005

The Honorable Nils J. Diaz
Chairman
U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE POINT BEACH NUCLEAR PLANT UNITS 1 AND 2

Dear Chairman Diaz:

During the 527th meeting of the Advisory Committee on Reactor Safeguards, November 3-5, 2005, we completed our review of the license renewal application for the Point Beach Nuclear Plant (PBNP) Units 1 and 2, and the final Safety Evaluation Report (SER) prepared by the NRC staff. We issued an interim report on the safety aspects of this application and the draft SER on June 9, 2005. Our Plant License Renewal Subcommittee also reviewed this matter during a meeting on May 31, 2005. During these reviews, we had the benefit of discussions with representatives of the NRC staff and the Nuclear Management Company, LLC (NMC). We also had the benefit of the documents referenced. This report fulfills the requirements of 10 CFR 54.25 that the ACRS review and report on all license renewal applications.

RECOMMENDATIONS

(1) With the inclusion of the conditions in Recommendation 2, the NMC application for license renewal of PBNP Units 1 and 2 should be approved.

(2) The staff should expand the scope of its post-approval site inspection to verify that all license renewal programs have been implemented and commitments have been met. In addition, the staff should review the effectiveness of the PBNP corrective action program (CAP) before PBNP enters the period of extended operation.

BACKGROUND AND DISCUSSION

The PBNP Units 1 and 2 are two-loop Westinghouse pressurized water reactors housed in dry ambient containments. Originally, each unit was licensed at a power level of 1519 MWt. Each unit has undergone a low-pressure turbine modification and a measurement uncertainty recapture power uprate to increase the power level to 1540 MWt. NMC has requested renewal of the operating licenses of Units 1 and 2 for 20 years beyond their current license terms, which expire on October 5, 2010, and March 8, 2013, respectively.

In the final SER, the staff documents its review of the license renewal application and other information submitted by the applicant and obtained through the audits and inspections at the plant site. The staff reviewed the completeness of the applicant's identification of structures, systems, and components (SSCs) that are within the scope of license renewal; the integrated plant assessment process; the applicant's identification of the plausible aging mechanisms associated with passive, long-lived components; the adequacy of the applicant's aging management programs; and the identification and assessment of time-limited aging analyses (TLAAs).

The PBNP application demonstrates consistency with, or documents deviations from, the approaches specified in the Generic Aging Lessons Learned Report. The staff questioned the applicant's approach to identifying nonsafety-related components whose failure could affect safety-related components. The applicant modified its scoping methodology to address the staff's questions. An inspection completed on August 17, 2005 confirmed that this methodology has been appropriately implemented. In the final SER, the staff concludes that the scoping and screening processes implemented by the applicant have successfully identified SSCs within the scope of license renewal and subject to an aging management review. We agree with this conclusion.

The applicant performed a comprehensive aging management review of all SSCs within the scope of license renewal. In the application, the applicant describes 26 aging management programs for license renewal, including existing, enhanced, and new programs. The draft SER identified 5 open items and 15 confirmatory items. The final SER describes the resolution of these items. We agree with the resolution of these items and with the staff's conclusion that the applicant's proposed aging management programs are adequate.

One of the open items relates to plant-specific operating experience of the two units. Containment liner corrosion due to borated water leakage has been identified in both units. The applicant has committed to performing augmented inspections in accordance with ASME Section XI Subsection IWE to monitor the extent of corrosion. The Boric Acid Corrosion Program is also credited with assessing and managing loss of material in the containment liner. The augmented inspection program does not include specific criteria for evaluation, repair, or replacement. At the staff's request, the applicant has agreed to include in the acceptance criteria element of the aging management program, "ASME Section XI, Subsections IWE and IWL Inservice Inspection Program," an appropriate discussion of the evaluation, repair or replacement criteria, and reexamination requirements necessary to ensure leak-tightness and structural integrity of the liner.

The applicant identified and reevaluated systems and components requiring TLAAs for 20 more years of operation. The upper shelf energy for both vessels and the reference temperature for pressurized thermal shock (PTS) for the Unit 2 vessel failed to meet the screening criteria.

To address the low upper shelf energy, the applicant performed equivalent margin analyses allowed by 10 CFR Part 50, Appendix G. These analyses yielded acceptable results through the end of the period of extended operation. The staff performed independent analyses to confirm the applicant's conclusion.

The intermediate-to-lower shell circumferential weld of the Unit 2 vessel is projected to exceed the PTS screening criterion in 2017. Consistent with the requirements of 10 CFR 54.21(c)(1)(iii), the applicant has chosen to manage the effects of aging of this weld during the period of extended operation. The applicant's commitments for PTS include implementing a low-low leakage fuel management pattern, using hafnium absorber assemblies, and documenting a flux reduction plan. This documentation will include any required safety analyses supporting continued operation. Other options the applicant may pursue include a more refined analysis of PTS or thermal annealing of the reactor pressure vessel.

In our June 9, 2005 interim report on the PBNP application, we expressed concern with the effectiveness of the PBNP CAP and the applicant's ability to effectively implement license renewal programs and meet commitments. We were concerned that the resources needed to address the staff's April 21, 2004 Confirmatory Action Letter to PBNP would compete with the effective development, tracking, and implementation of license renewal programs and commitments. We recommended that, prior to the units entering the period of extended operation, the staff take additional actions to increase confidence that the requirements of the license renewal rule have been met. We suggested, for example, an expanded inspection of license renewal commitments and a focused review of the effectiveness of the CAP. The PBNP remains in the Multiple/Repetitive Degraded Cornerstone column of the Reactor Oversight Process Action Matrix, and there are still weaknesses in the CAP.

In its July 15, 2005 response to the Committee, the staff described the inspections being conducted at PBNP to verify that license renewal programs and commitments are appropriate and consistent with the rule. However, detailed development and implementation of many of these programs and commitments will occur after the license is renewed and prior to the license renewal period. The staff plans to perform a post-approval site inspection in accordance with Inspection Procedure 71003 before the period of extended operation begins.

Inspection Procedure 71003 is the standard inspection that the staff performs prior to the period of extended operation. This inspection evaluates only a sample of the license renewal commitments and programs. In light of the applicant's weakness in managing commitments, as discussed in our interim report, the staff should expand the scope of the post-approval site inspection to verify that all license renewal programs have been implemented and commitments have been met. In addition, before PBNP enters the period of extended operation, the staff should review the effectiveness of the CAP. These actions are necessary to ensure that there is reasonable assurance that aging degradation can be adequately managed.

With a commitment to perform the expanded inspections described above, the application for renewal of the operating licenses of the PBNP Units 1 and 2 should be approved.

Sincerely,

/RA/

Graham B. Wallis
Chairman

References:
1. Nuclear Management Company, LLC, "Application for Renewed Operating Licenses Point Beach Nuclear Plant Units 1 & 2," February 2004.
2. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2," May 2005.
3. U.S. Nuclear Regulatory Commission, "Safety Evaluation Report Related to the License Renewal of the Point Beach Nuclear Plant, Units 1 and 2," October 2005.
4. Letter from Graham B. Wallis, Chairman, ACRS, to Luis A. Reyes, Executive Director for Operations, NRC; "Interim Report on the Safety Aspects of the License Renewal Application for the Point Beach Nuclear Plant, Units 1 and 2," June 9, 2005.
5. Pacific Northwest National Laboratory, "Audit and Review Report for Plant Aging Management Reviews and Programs, Point Beach Nuclear Plant Units 1 and 2," April 11, 2005.
6. U.S. Nuclear Regulatory Commission, "Point Beach Nuclear Plant, Units 1 and 2 NRC License Renewal Scoping, Screening, and Aging Management Inspection Report 05000266/2005005 (DRS); 05000301/2005005 (DRS)," May 2, 2005.
7. U.S. Nuclear Regulatory Commission, "Point Beach Nuclear Plant, Units 1 and 2 NRC License Renewal Followup Inspection Report 05000266/2005015 (DRS); 05000301/2005015 (DRS)," September 9, 2005.
8. U.S. Nuclear Regulatory Commission, "Point Beach Nuclear Plant, Units 1 and 2 NRC Special Inspection Report 05000266/2005011; 05000301/2005011," September 23, 2005.
9. U.S. Nuclear Regulatory Commission, "Point Beach Nuclear Plant, Units 1 and 2 NRC Special Emergency Preparedness Inspection Report 05000266/2005009 (DRS); 05000301/2005009 (DRS)," August 2, 2005.

10. Letter from J. Dyer, Regional Administrator, to M. Warner, Site Vice President, Kewaunee and Point Beach Nuclear Plants, Nuclear Management Company, LLC, "Point Beach Special Inspection - NRC Inspection Report 50-266/01-17(DRS); 50-301/01-17(DRS), Preliminary Red Finding," April 3, 2002.
11. Letter from J. Dyer, Regional Administrator, to M. Warner, Site Vice President, Kewaunee and Point Beach Nuclear Plants, Nuclear Management Company, LLC, "Point Beach Nuclear Plant Final Significance Determination for a Red Finding and Notice of Violation NRC Special Inspection Report No. 50-266/01-17(DRS; 50-301/01-17(DRS)," July 12, 2002.
12. Letter from J. Dyer, Regional Administrator, to A. Cayia, Site Vice President, Point Beach Nuclear Power Plant, Nuclear Management Company, LLC, "Point Beach Nuclear Plant Special Inspections: Resolution of Auxiliary Feedwater Old Design Issue and Preliminary Red Finding - Auxiliary Feedwater Orifice Plugging Issue; NRC Inspection Report 50-266/02-15(DRP); 50-301/02-15(DRP)," April 2, 2003.
13. Letter from J. Caldwell, Regional Administrator, to A. Cayia, Site Vice President, Point Beach Nuclear Plant, Nuclear Management Company, LLC, "Point Beach Nuclear Plant, Units 1 and 2 Final Significance Determination for a Red Finding and Notice of Violation (NRC Inspection Report No. 50-266/02-15(DRP); 50-301/02-15(DRP))," December 11, 2003.
14. Letter from G. Van Middlesworth, Site Vice President, Point Beach Nuclear Plant, Nuclear Management Company, LLC, to U.S. Nuclear Regulatory Commission Document Control Desk, "Commitments in Response to 95003 Supplemental Inspection," March 22, 2004.
15. Letter from J. Caldwell, Regional Administrator, to G. Van Middlesworth, Site Vice President, Point Beach Nuclear Plant, Nuclear Management Company, LLC, "Confirmatory Action Letter," April 21, 2004.
16. Letter from J. Caldwell, Regional Administrator, to D. Koehl, Site Vice President, Point Beach Nuclear Plant, Nuclear Management Company, LLC, "Annual Assessment Letter - Point Beach Nuclear Plant (Report 05000266/200501; 05000301/200501)," March 2, 2005.
17. Letter from D. Koehl, Site Vice-President, Point Beach Nuclear Plant, Nuclear Management Company, LLC, to U.S. Nuclear Regulatory Commission Document Control Desk, "License Renewal Application Revised Information," September 10, 2004.
18. Memorandum from L. Reyes, EDO, to Chairman Diaz, Commissioner McGaffican, and Commissioner Merrifield, "Pressurized Thermal Shock Analyses for Renewal of Certain Nuclear Power Plant Operating Licenses," May 27, 2004.

SECTION 6

CONCLUSION

The staff of the U.S. Nuclear Regulatory Commission (NRC or the Commission) reviewed the license renewal application for the Point Beach Nuclear Plant, Units 1 and 2, in accordance with the 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 application, 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 10 CFR Part 51, Subpart A, are documented in NUREG-1437, Supplement 23, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants: Regarding Point Beach Nuclear Plant, Units 1 and 2, Final Report," dated August 12, 2005.

APPENDIX A

COMMITMENTS FOR LICENSE RENEWALS OF PBNP Units 1 and 2

During the review of the Point Beach Nuclear Plant Units 1 and 2 LRA, the applicant made commitments related to aging management programs (AMPs) to manage aging effects of structures and components (SCs) prior to the period of extended operation. The following table lists these commitments, along with the implementation schedules and the sources of the commitment.

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
1	A License Renewal flag for each component will be maintained as part of the equipment information database	Prior to Period of Extended Operation	LRA Section 1.0, NRC 2004-0016
2	RI-ISI Program inspections of piping welds less than 4-inch NPS will include volumetric examinations for non-socket welds and surface examination for socket welds.	Continue as Part of RI-ISI	LRA Section 2.1.1.3.8, 3.1 and Table 3.1.0-1, NRC 2004-0016
3	All concrete/grout at Point Beach that is within the scope of license renewal, will be managed for aging.	Prior to Period of Extended Operation	LRA Section 3.0.1.9, NRC 2004-0016
4	Point Beach will continue to monitor and participate in industry initiatives with regard to baffle/former and barrel/former bolt performance to support aging management for the Unit 1 bolting.	Prior to Period of Extended Operation	LRA Sections 3.1.2.2.3.3, 3.1.2.2.8 and Table 3.1.0-2, NRC 2004-0016
5	PBNP will continue to participate in industry investigations of aging effects applicable to reactor vessel internals. Aging management activities or surveillance techniques resulting from these initiatives will be incorporated, as required, as enhancements to the Reactor Vessel Internals Program.	Prior to Period of Extended Operation	LRA Sections 3.1.2.2.6 and 3.1.2.2.9, NRC 2004-0016
6	PBNP will incorporate applicable results of industry initiatives related to void swelling in the Reactor Vessel Internals Program.	Prior to Period of Extended Operation	LRA Section 3.1.2.2.6 and Table 3.1.1, NRC 2004-0016

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	Commitment	Implementation Schedule	Source
7	Plant process control procedures (design control, repair/replacement, and welding) will be revised to ensure that repair or replacement of Class 1 piping components within the scope of LBB analysis (welded connections or CASS) would require a new LBB analysis based on replacement process and/or material properties.	Prior to Period of Extended Operation	LRA Table 3.1.0-1, NRC 2004-0016
8	PBNP will implement the NRC-approved industry activities resulting from the MRP, as appropriate, to manage any applicable aging effects identified through the EPRI MRP effort (RVI Related).	Prior to Period of Extended Operation	LRA Table 3.1.0-2, NRC 2004-0016
9	The Periodic Surveillance and Preventive Maintenance Program will be used to replace the program designated bolting.	Prior to Period of Extended Operation	LRA Tables 3.1.2-1 through 3.1.2-6, Tables 3.2.2-1 through 3.2.2-4, Tables 3.3.3-1 through 3.3.3-16, Tables 3.4.2-1 through 3.4.2-3, and Tables 3.5.2-1 through 3.5.2-14, NRC 2004-0016
10	The integrity of the RPV will be directly validated with the testing of the capsule installed on Unit 2 in 2002, should extended operation be considered.	When Fluence Levels Reach Those Anticipated for End of the Renewed License Period	LRA Section 4.1.2, NRC 2004-0016
11	Capsule A2 (Unit 1) will be removed at a target EOLE fluence of 3.7×10^{19} n/cm^2.	Removal at Fluence Described	LRA Secion 4.2, NRC 2004-0016

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
12	The upper shelf energy evaluation will be revised prior to entering into the extended period of operation.	Prior to Period of Extended Operation	LRA Section 4.2, NRC 2004-0016
13	Implement an enhanced ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.1, NRC 2004-0016
14	Implement an enhanced ASME Section XI, Subsections IWE and IWL Inservice Inspection Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.2, NRC 2004-0016
15	Implement an enhanced ASME Section XI, Subsections IWF Inservice Inspection Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.3, NRC 2004-0016
16	Implement an enhanced Bolting Integrity Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.4, NRC 2004-0016
17	Implement an enhanced Boraflex Monitoring Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.5, NRC 2004-0016
18	Implement an enhanced Boric Acid Corrosion Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.6, NRC 2004-0016
19	Develop and implement a Buried Services Monitoring Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.7, NRC 2004-0016

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule.**	**Source**
20	Develop and implement a Cable Condition Monitoring Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.8, NRC 2004-0016
21	Implement an enhanced Closed-Cycle Cooling Water System Surveillance Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.9, NRC 2004-0016
22	Implement an enhanced Fire Protection Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.10, NRC 2004-0016
23	Implement an enhanced Flow-Accelerated Corrosion Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.11, NRC 2004-0016
24	Implement an enhanced Fuel Oil Chemistry Control Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.12, NRC 2004-0016
25	Develop and implement a One-Time Inspection Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.13, NRC 2004-0016
26	Implement an enhanced Open-Cycle Cooling (Service) Water System Surveillance Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.14, NRC 2004-0016
27	Implement an enhanced Periodic Surveillance and Preventive Maintenance Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.15, NRC 2004-0016

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
28	Develop and implement a Reactor Coolant System Alloy 600 Inspection Program.	Prior to the Period of Extended Operation and Consistent with Commitments Made in Response to NRC Bulletin 2002-02 and Requirements of NRC Order EA-03-009	LRA Appendix A and Appendix B2.1.16, NRC 2004-0016, NRC 2005-0056
29	Implement an enhanced Reactor Vessel Internals Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.17, NRC 2004-0016
30	Implement an enhanced Reactor Vessel Surveillance Program.	Implementation Prior to Need to Assess Condition of Surveillance Capsule	LRA Appendix A and Appendix B2.1.18, NRC 2004-0016
31	Implement an enhanced Steam Generator Integrity Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.19, NRC 2004-0016
32	Implement an enhanced Structures Monitoring Program.	Prior to Period of Extended Operation	LRA Table 3.5.0-1 Line 8, and Appendix B2.1.20, NRC 2004-0016
33	Implement an enhanced Systems Monitoring Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.21, NRC 2004-0016

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	Commitment	Implementation Schedule	Source
34	Develop and implement a Tank Internal Inspection Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.22, NRC 2004-0016
35	Implement an enhanced Thimble Tube Inspection Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.23, NRC 2004-0016
36	Implement an enhanced Water Chemistry Control Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B2.1.24, NRC 2004-0016
37	Implement an enhanced EQ Program.	Prior to Period of Extended Operation	LRA Appendix A and Appendix B3.1, NRC 2004-0016
38	Implement an enhanced Fatigue Monitoring Program.	Prior to Period of Extended Operation	LRA Appendix A, Table 3.1.0-2 Line 11 and Appendix B3.2, NRC 2004-0016
39	A Reactor Vessel Internals Program will be submitted to the NRC for review and approval.	Two Years Prior to Entering Period of Extended Operation	NRC 2004-0071
40	Scoping, Screening and Aging Management Review results from the recent Auxiliary Feedwater System area modifications will be provided as part of the LRA annual update of current licensing basis	COMPLETED	NRC 2004-0083 and NRC 2005-0020
41	Two penetrations in the Unit 2 Containment will be opened and inspected during the spring 2005 refueling outage.	COMPLETED	NRC 2004-0086

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	Commitment	Implementation Schedule	Source
42	The Structures Monitoring Program will be enhanced to conduct and document a structural condition survey of the reactor vessel sump area.	Prior to Period of Extended Operation	NRC 2004-0086
43	Final tendon stress and trend calculation results will be provided if the results are different than those provided in this response.	COMPLETED	NRC 2004-0086
44	The Structures Monitoring Program will be updated as part of the LRA annual updated to include wood as a material to be inspected.	COMPLETED	NRC 2004-0086 NRC 2005-0020
45	As part of LRA Section B.2.1.13, "One Time Inspection Program," a one-time visual inspection and hardness measurement will be performed on accessible locations of a select set of components of each material type (i.e., cast iron and brass) to determine whether selective leaching has occurred and whether the resulting loss of strength and/or material will affect the intended functions of these components during the period of extended operation.	Prior to Period of Extended Operation	NRC 2004-0101
46	PBNP will continue to implement the low-low leakage loading fuel management pattern to minimize the limiting weld fluence. In addition, PBNP will continue operation with Hafnium absorber assemblies in service until the resolution of the Unit 2 intermediate-to-lower shell girth weld PTS issue via an alternative analysis methodology.	Ongoing Existing Program	NRC 2004-0111

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
47	Documentation of a flux reduction program and other options, as necessary, allowed by 10 CFR 50.61(b) for the Unit 2 Reactor Pressure Vessel intermediate-to-lower shell girth weld will be completed within one year of receipt of the extended license. Documentation within this time frame will support submittal of any required safety analysis at least three years prior to the time frame that RT_{PTS} for Unit 2 is projected to exceed the screening criteria.	December 31, 2006 Existing Program	NRC 2004-0111
48	If acceptable PTS results cannot be provided prior to EOL with alternate analysis techniques, the PBNP flux reduction program will evaluate the feasibility and practicality of pursuing additional aggressive flux reduction measures prior to EOL, such as the insertion of part length shielded fuel assemblies.	March 8, 2013 Existing Program	NRC 2004-0111
49	NMC will add line items to LRA Table 3.3.2-2 to include stainless steel under the Component Type, "Piping and Fittings" to address the flexible tubing as part of the LRA annual update	COMPLETED	NRC 2004-0135
50	As part of the Steam Generator Integrity Program, visual inspections of accessible areas to verify the integrity of steam generator secondary-side components will be performed at least every six years, with one steam generator being inspected every three years on an alternating basis. Any indications of degradation or unacceptable conditions will be evaluated through the corrective action program, including the extent of condition.	Per Steam Generator Integrity Program	NRC 2005-0006
51	NMC will monitor on-going industry activities related to failure mechanisms for small-bore piping, and will evaluate changes to PBNP inspection activities based on industry recommendations.	Prior to Period of Extended Operation	NRC 2005-0002

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
52	NMC will use the interim report "PWR Materials Reliability Project Interim Alloy 600 Safety Assessment for US PWR Plants (MRP-44), Part 1: Alloy 82/182 Pipe Butt Welds," and its final version as part of the basis for the Reactor Coolant System Alloy 600 Inspection Program.	October 8, 2008	NRC 2005-0002
53	NMC will submit the Reactor Coolant System Alloy 600 Inspection Program 24 - 36 months prior to the period of extended operation for staff review and approval to determine if the program demonstrates the ability to manage the effects of aging per 10 CFR 54.21(a)(3).	October 8, 2008	NRC 2005-0002
54	NMC will remove the "Exposure Duration" discussion from LRA Section 2.1.2.1.2 and will summarize the response to RAI 2.1.1 in the "Components Qualified/Designed for Environment" discussion as part of the LRA annual update.	COMPLETED	NRC 2005-0001
55	As part of the Cable Condition Monitoring Program, a representative sample of in-scope, inaccessible non-EQ medium-voltage cables not designed for submergence subject to significant moisture and significant voltage will be tested prior to the end of the current license period and once every ten years during the period of extended license. This sample will include the most susceptible cables and be representative of all cable types and manufacturers. The basis for this representative sample will be documented. Significant moisture is defined as periodic exposure that lasts more than a few days (*i.e.*, cable in standing water) which is consistent with NUREG-1801, Section XI.E3.	Prior to Period of Extended Operation	NRC 2005-0026

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
56	Periodic visual inspections of the bus duct will be performed as part of the Periodic Surveillance and Preventive Maintenance Program to inspect for signs of insulation cracking, corrosion, debris, excessive dust buildup, evidence of moisture and water intrusion, or discoloration of insulation.	Prior to Period of Extended Operation	NRC 2005-0026
57	Enhancements will be made to the Structural Monitoring Program to include the primary shield and reactor vessel support areas.	Prior to Period of Extended Operation	NRC 2005-0026
58	A susceptible location in the Fire Protection System (*i.e.*, uncoated/unwrapped piping) will be scheduled to be inspected once prior to the period of extended operation and at least every 10 years during the period of extended operation. Based upon findings from these Fire Protection System inspections, additional inspection locations could include coated and/or uncoated buried piping in the Fire Protection System, Service Water System and Fuel Oil System.	Prior to Period of Extended Operation	NRC 2005-0026
59	NMC will conduct eddy current inspections under the One-Time Inspection Program of the tubing of one RHR heat exchanger or replace the RHR heat exchanger tube bundles prior to the period of extended operation if eddy current testing of the tubing of at least one RHR heat exchanger is not completed.	Prior to Period of Extended Operation	NRC 2005-0037

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
60	As part of the Bolting Integrity Program, maintenance instructions will be revised as necessary to clearly state that lubricants containing molybdenum disulfide should not be used unless evaluated on a case-by-case basis with consideration given for the potential of stress corrosion cracking (SCC). NMC will continue to use locking devices per the design codes, standards and specifications applicable to PBNP. NMC will continue to follow the requirements of 10CFR 50.55a or request relief, as necessary, regarding the qualification and certification of NDE personnel. NMC will clarify that the prohibition against reuse of any bolt or nut tightened by the turn-of-nut method only applies to component support bolting installed in accordance with American Institute of Steel Construction (AISC) or similar design specifications in which the turn-of-nut method may result in the bolting material being stressed beyond yield.	Prior to Period of Extended Operation	NRC 2005-0037
61	NMC will provide the One-Time Inspection Program methodology for NRC review to detail the sample size selection criteria and specific component identification criteria within that sample.	COMPLETED	NRC 2005-0037, Inspection Report 0500266/2005015 (DRS), 0500301/2005015 (DRS)

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
62	All systems within the scope of license renewal containing components requiring an aging management review and that credit the Systems Monitoring Program for managing the effects of aging on the external surfaces of the components will be walked down at a minimum frequency of once per operating cycle, within the limits of accessibility. A supervisory review will be performed and documented to ensure that the accessible portions of each system are walked down at a minimum frequency of once per operating cycle. Those portions of a system that are considered inaccessible will be evaluated to ensure that accessible portions of the system that are walked down contain the same material(s) and the same or more severe environment(s) as those portions that are considered inaccessible. When an unacceptable condition or situation is identified in an accessible portion of a system, an extent of condition evaluation will be performed to determine whether the same condition or situation is applicable to other accessible or inaccessible portions of the system.	Prior to the period of extended operation	NRC 2005-0037

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	Commitment	Implementation Schedule	Source
63	If degradation is detected by the Flow-Accelerated Corrosion Program such that wall thickness is less than or equal to 87.5 percent of nominal wall thickness for safety-related piping additional examinations will be performed in adjacent areas to bound the thinning. For both safety-related and nonsafety-related piping, additional examinations will be performed in adjacent areas to bound the thinning if the remaining service life, based on the code minimum allowable wall thickness, is less than one operating cycle. The sample size will also be expanded for nonsafety-related piping if degradation is detected such that the wall thickness is less than or equal to 60 percent of nominal wall thickness. This covers situations where the code minimum allowable wall thickness may be less than 60 percent of nominal wall thickness for nonsafety-related piping.	Prior to the period of extended operation	NRC 2005-0037 NRC 2005-0044
64	As part of the Periodic Surveillance and Preventive Maintenance Program, records of deferrals, cancellations, and frequency changes for callups credited for License Renewal as aging management or replacement activities will be retained in an auditable and retrievable form.	Prior to the period of extended operation	NRC 2005-0037

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
65	Certain accelerated Boraflex panels will be areal density and blackness tested every two years during the period of extended operation. The first Boraflex areal density testing of the Boraflex panels will be performed prior to the period of extended operation. A new procedure to schedule and perform Boraflex areal density and blackness testing will be created. If silica sampling and trending indicates a boron areal density depletion trend to a value less than the acceptance criteria (*i.e.*, maintaining the 5 percent subcriticality margin) prior to the next scheduled test, then an evaluation will be performed within the corrective action program and the frequency of blackness and areal density testing increased. Corrective actions will be taken to ensure that the 5 percent subcriticality margin of the spent fuel racks in the SFP is maintained during the period of extended operation. Corrective actions will be initiated if the test results find that the 5 percent subcriticality margin cannot be maintained because of current or projected future degradation. Corrective actions may include, but are not necessarily limited to, the following: (1) Re-analysis (2) Repair and/or Replacement	Prior to Period of Extended Operation	NRC 2005-0038

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
66	As a part of the ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program, the requirements of Code Case N-616 will be supplemented by a VT-2 visual examination performed each outage for Class 1 systems and each inspection period for Class 2 and 3 systems with the insulation removed from the bolted connections. The connections are not pressurized during these examinations.	Prior to the Period of Extended Operation	NRC 2005-0071
67	NMC will use enhanced volumetric examination to detect and size cracks or a plant- or component-specific flaw tolerance evaluation to demonstrate that cast austenitic stainless steel (CASS) primary loop elbows potentially susceptible to thermal embrittlement have adequate fracture toughness.	Prior to the Period of Extended Operation	NRC 2005-0044
68	NMC will age manage the steam generator (SG) feedrings, J-nozzles, and feedring supports using the Water Chemistry Control Program and the Steam Generator Integrity Program.	Prior to the Period of Extended Operation	NRC 2005-0044
69	The Structures Monitoring Program will examine below-grade concrete when it is exposed by excavation for signs of degradation from aggressive chemical attack or corrosion of embedded steel, during the period of extended operation. Periodic monitoring of ground water chemistry (pH, chlorides, sulfates) will continue to be performed during the period of extended operation to ensure the environment remains non-aggressive. The frequency of monitoring ground water chemistry (pH, chlorides, sulfates) will be at least once every 5 years.	Prior to the Period of Extended Operation	NRC 2005-0044

APPENDIX A: COMMITMENTS FOR LICENSE RENEWAL OF PBNP			
Item No.	**Commitment**	**Implementation Schedule**	**Source**
70	The following aging management programs will be revised to credit the One-Time Inspection Program to identify selective leaching of susceptible components: • Open-Cycle Cooling (Service) Water System Surveillance Program • Fire Protection Program • Systems Monitoring Program • Periodic Surveillance and Preventive Maintenance Program • Structures Monitoring Program	Prior to the Period of Extended Operation	NRC 2005-0056
71	An evaluation, repair or replacement requirement discussion will be included in the Acceptance Criteria element of the ASME Section XI, Subsections IWE and IWL Inservice Inspection Program of the LRA prior to the period of extended operation. If localized area thickness of the containment liner base metal is reduced by 50% or more of the nominal plate thickness, then every attempt should be made to correct by repair or replacement. If the repair or replacement option is impractical, an acceptance by engineering evaluation option may be pursued.	Prior to the Period of Extended Operation	NRC 2005-0086
72	If localized area thickness of the base metal is reduced by approximately 50% or more of the nominal plate thickness, then the reexaminations required by IWE 2420(b) will be continued in the succeeding inspection periods and the provisions of IWE-2420(c) will not be applied.	Prior to the Period of Extended Operation	NRC 2005-0086

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 Nuclear Management Company, LLC (NMC), and other correspondence regarding the staff's reviews of the Point Beach Nuclear Plant Units 1 and 2 (PBNP), Docket Numbers 50-266 and 50-301, license renewal application (LRA).

February 25, 2004	PBNP Transmittal of Application for Renewed Operating Licenses, including Environmental Report (Accession No. ML040580023)
February 25, 2004	PBNP Application for Renewed Operating Licenses, including FSAR Supplement (Accession No. ML040580024)
February 25, 2004	PBNP Transmittal of License Renewal Drawings to Aid in Review of the LRA (Accession No. ML040630451)
February 25, 2004	PBNP Applicant's Environmental Report - Operating License Renewal Stage (Accession No. ML040580025)
February 26, 2004	Notice of March 9, 2004 Meeting Between NRC and NMC to Discuss the LRA for PBNP (Accession No. ML040570714)
March 1, 2004	NRC Press Release-04-029: NRC Announces Availability of License Renewal Application for Point Beach Nuclear Power Plant (Accession No. ML040611048)
March 2, 2004	Receipt and Availability of LRA for PBNP (Accession No. ML040640628)
March 19, 2004	Notice of March 31, 2004 Public Information Session for NRC to Describe Its License Renewal Process (Accession No. ML040790211)
March 24, 2004	NRC Press Release-III-04-014: Public Meeting March 31 On License Renewal Application for Point Beach Nuclear Power Plant (Accession No. ML040840575)
April 7, 2004	Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding the Applications from NMC for Renewal of the Operating Licenses for PBNP (TAC Nos. MC2099 and MC2100) (Accession No. ML040980219)
April 15, 2004	Summary of March 9, 2004 Meeting with NMC Regarding the PBNP LRA (Letter) (Accession No. ML041280264)
April 15, 2004	Summary of March 9, 2004 Meeting with NMC Regarding the PBNP LRA (Enclosure) (Accession No. ML041180131)

April 16, 2004	NRC Press Release-04-042: NRC Announces Opportunity for Hearing on Application to Renew Operating Licenses for PBNP, Units 1 and 2 (Accession No. ML041070354)
April 22, 2004	Summary of March 31, 2004 Public Meeting Regarding the LRA for PBNP - Slides (Enclosure 3) (Accession No. ML041180238)
April 22, 2004	Summary of March 31, 2004 Public Meeting Regarding the LRA for PBNP - Letter and Enclosures 1 through 2 (Accession No. ML041170437)
May 5, 2004	PBNP License Renewal Review (Accession No. ML041270559)
May 5, 2004	PBNP License Renewal Review (Accession No. ML041270553)
May 17, 2004	NRC Review of PBNP LRA (Accession No. ML041410580)
May 21, 2004	NRC review of PBNP LRA (Accession No. ML041450239)
May 26, 2004	Questions and Responses - Summary of May 3, 2004 Telephone Conference Between NRC and NMC Concerning Receipt of Aging Management Program Post-Audit Requests for Additional Information Pertaining to the PBNP LRA (TAC Nos. MC2049 and MC2050) (Accession No. ML041610159)
May 26, 2004	Summary of May 3, 2004 Telephone Conference Between NRC and NMC Concerning Receipt of Aging Management Program Post-Audit Requests for Additional Information Pertaining to the PBNP LRA (TAC Nos. MC2049 and MC2050) (Accession No. ML041610149)
June 3, 2004	Audit and Review Plan for Plant Aging Management Reviews and Programs - PBNP (Accession No. ML041550860)
June 4, 2004	Notice of June 24, 2004 Meeting with NMC on License Renewal Scoping and Screening Methodology Audit for PBNP (Accession No. ML041560474)
June 8, 2004	NRC Press Release-04-037: NRC to Hold Public Meeting June 15, 2004 on Proposed License Renewal of PBNP, Units 1 and 2 (Accession No. ML0416000585)
June 15, 2004	Transcript of June 15, 2004 Public Meeting on Point Beach License Renewal (Accession No. ML041900071)
June 15, 2004	Transcript of June 15, 2004 Public Meeting on PBNP License Renewal (Accession No. ML041830450)
June 29, 2004	Audit and Review Plan for Plant Aging Management Reviews and Programs at PBNP (Accession No. ML041880324)

June 29, 2004	Notice of July 15, 2004 Exit Meeting with NMC on License Renewal Audits of Aging Management Programs and Reviews for PBNP (Accession No. ML041810419)
July 1, 2004	Scoping Comments for Proposed Operating License Renewal for PBNP (Accession No. ML041910394)
July 8, 2004	Summary of Public Scoping Meetings to Support Review of the PBNP LRA (TAC Nos. MC2049 and MC2050) (Accession No. ML041960112)
July 12, 2004	NMC PBNP LRA Clarifications (TAC Nos. MC2099 and MC2100) (Accession No. ML042030310)
July 12, 2004	NMC PBNP LRA Clarifications (TAC Nos. MC2099 and MC2100) (Accession No. ML041960159)
July 22, 2004	Notice of August 3, 2004 Meeting Between NRC and NMC to Discuss the LRA for PBNP (Accession No. ML042040430)
July 27, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML042110308)
July 30, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML042150431)
August 5, 2004	Summary of Telephone Conference Held on June 24, 2004 Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML042260399)
August 19, 2004	Summary of Telephone Conference Held on July 15, 2004 Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML042320653)
August 26, 2004	NMC Response to NRC Request for Additional Information Regarding Sections 3.5 and 4.5 of the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML042510486)
August 30, 2004	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML042530053)
August 31, 2004	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML042530218)
September 10, 2004	NMC PBNP LRA Revised Information (TAC Nos. MC2099 and MC2100) (Accession No. ML042660308)
September 10, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML042570040)

September 14, 2004	Summary of August 3, 2004 Meeting With NMC Regarding the PBNP LRA Concerning Reactor Vessel Integrity Evaluations (Accession No. ML042590062)
September 16, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML042610283)
September 17, 2004	Summary of September 2, 2004 Telephone Conference with NMC Regarding Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML042640263)
September 23, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML042680140)
September 23, 2004	NRC Audit Trip Report on Point Beach License Renewal Scoping and Screening Methodology Audit From June 21-24, 2004 (Accession No. ML042660542)
September 30, 2004	NRC Audit Trip Report Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML042730603)
October 8, 2004	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML042940439)
October 15, 2004	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML042990534)
October 19, 2004	Notice of October 28, 2004 Meeting with NMC to Discuss the Responses to Requests for Additional Information in the License Renewal review for PBNP (Accession No. ML042930124)
October 21, 2004	Summary of August 19, 2004 Telephone Conference Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML042990506)
October 25, 2004	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML043080122)
November 10, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043170663)
November 12, 2004	Summary of September 13, 2004 Telephone Conference Between NRC and NMC Regarding Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML043170664)

November 16, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043270609)
November 16, 2004	Summary of October 26, 2004 Telephone Conference Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML043270587)
November 16, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043270539)
November 17, 2004	Summary of October 27, 2004 Telephone Conference Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML043270654)
November 17, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043270653)
November 17, 2004	Summary of November 17, 2004 Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML043270652)
November 17, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043270651)
November 17, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043270650)
November 17, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043270647)
November 17, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043270644)
November 18, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043280582)
November 18, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043280552)
November 18, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043280488)
November 18, 2004	Summary of November 5, 2004 Telephone Conference Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML043270656)
November 22, 2004	Summary of October 28, 2004 Telephone Conference with NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML043280684)

December 14, 2004	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML043570457)
December 16, 2004	Summary of December 15, 2004 Telephone Conference Between NRC and NMC Concerning Draft Requests For Additional Information Pertaining to the PBNP LRA (Accession No. ML050060167)
December 17, 2004	Summary of December 16, 2004 Telephone Conference Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050060298)
December 17, 2004	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML043620366)
December 17, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043560416)
December 20, 2004	Summary of December 17, 2004 Telephone Conversation Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050060357)
December 21, 2004	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML043640289)
December 21, 2004	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML043570510)
December 21, 2004	Summary of December 16, 2004 Telephone Conversation Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML043570282)
December 21, 2004	Summary of October 28, 2004 Telephone Conference Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML043570259)
December 22, 2004	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050040178)
December 22, 2004	Summary of November 5, 2004 Telephone Conference Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML043570455)
January 6, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050180203)

January 7, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050180271)
January 10, 2005	Summary of January 5, 2005 Telephone Conference Between NRC and NMC Concerning Draft Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050130192)
January 10, 2005	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML050110469)
January 12, 2005	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML050130356)
January 13, 2005	NUREG-1437, Supplement 23, Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding Point Beach Nuclear Plant Units 1 and 2, Draft Report for Comment (Accession No. ML050130187)
January 17, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050540591)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050270046)
January 19, 2005	Summary of January 14, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050270037)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260699)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260636)
January 19, 2005	Summary of January 5, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260585)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260473)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260435)

January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260421)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260391)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260359)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260353)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260319)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260303)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260247)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050260237)
January 19, 2005	Summary of January 10, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050250436)
January 21, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050330400)
January 25, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050340201)
January 25, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050340198)

January 25, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050340169)
January 25, 2005	Summary of January 5, 2005 Telephone Conference Between NRC and NMC Concerning Requests for Additional Information Pertaining to the PBNP LRA (Accession No. ML050270121)
January 26, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050340166)
January 26, 2005	NRC Request for Additional Information for Review of the PBNP LRA (Accession No. ML050260697)
January 28, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) and Request for Withholding of Proprietary Information from Public Disclosure (Accession No. ML050400483)
January 28, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050400109)
January 31, 2005	NMC Response to NRC Request for Additional Information Regarding the PBNP LRA (Accession No. ML050400134)
February 4, 2005	Notice of February 15, 2004 Meeting Between NRC and NMC To Discuss the LRA for PBNP (Accession No. ML050350245)
February 7, 2005	NRC Confirmation of Information Verbally Provided to NRC Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050460279)
February 7, 2005	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML050380148)
February 23, 2005	NRC Request for Additional Information for Review of the PBNP LRA (Accession No. ML050540542)
February 23, 2005	NMC Amendment to the PBNP LRA (Accession No. ML050610283)
February 25, 2005	NMC Response to Request for Additional Information Regarding the PBNP LRA (Accession No. ML050670488)
March 3, 2005	Summary of February 15, 2005 Meeting Between NRC and NMC to Discuss PBNP LRA (Accession No. ML050620498)
March 4, 2005	NMC Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050740128)

March 4, 2005	NMC Response to Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050740122)
March 15, 2005	NMC Clarification to Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050840432)
March 15, 2005	NMC Response to Request for Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050840431)
March 24, 2005	Public Meeting to Discuss the NRC's License Renewal Inspection at PBNP (Accession No. ML050840198)
March 24, 2005	Notice of Significant Licensee Meeting with NMC to Discuss Results of Scoping, Screening and Aging Management License Renewal Inspection at PBNP (Accession No. ML050840175)
March 29, 2005	NRC Request for Additional Information for the Review of the PBNP LRA (Accession No. ML050880194)
March 30, 2005	NRC Request for Additional Information for the Review of the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050890003)
March 31, 2005	NRC Request for Additional Information for the Review of the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML050910217)
April 1, 2005	NMC Response to Request for Additional Information Regarding the PBNP LRA (Accession No. ML051020357)
April 8, 2005	Clarification to Information Regarding the PBNP LRA (Accession No. ML051090337)
April 11, 2005	Audit and Review Report for Plant Aging Management Reviews and Programs, PBNP, Units 1 and 2, Revision 1 (Accession No. ML051020288)
April 15, 2005	Summary of March 31, 2005 Telephone Conference Between NRC and NMC Regarding to PBNP LRA (Accession No. ML051050312)
April 29, 2005	NMC Response to Request for Additional Information Regarding the PBNP LRA (Accession No. ML051300349)
April 29, 2005	Clarification to Information Regarding the PBNP LRA (Accession No. ML051300355)
May 2, 2005	Letter from NRC to D. Koehl Regarding the SER with Open Items Related to License Renewal at PBNP, Units 1 and 2 (Accession No. ML051230024)

May 2, 2005	Draft Safety Evaluation Report related to PBNP, Units 1 and 2 (Accession No. ML051190124)
May 2, 2005	Point Beach Nuclear Plant, Units 1 and 2, NRC License Renewal Scoping, Screening, and Aging Management Inspection Report (05000266/2005005 (DRS), 05000301/2005005(DRS)) (Accession No. ML051220260)
May 25, 2005	NRC Press Release-05-084: NRC Advisory Committee on Reactor Safeguards to Meet on June 1-3 in Rockville, Maryland (Accession No. ML051450211)
May 31, 2005	Transcript of Advisory Committee on Reactor Safeguards Plant License Renewal Subcommittee meeting, May 31, 2005 in Rockville, Maryland (Accession No. ML051710223)
June 9, 2005	Letter from Graham B. Wallis, ACRS, to Luis A. Reyes, EDO, Regarding the Interim Report on the Safety Aspects of the PBNP LRA (G20050428) (Accession No. ML051680321)
June 9, 2005	NMC Response to Request for Additional Information Regarding the PBNP LRA (Accession No. ML051680493)
June 10, 2005	NMC Response to SER with Open Items Regarding the PBNP LRA (Accession No. ML051720463)
June 13, 2005	Summary of March 3, 2005 Telephone Conference between NRC and NMC (Accession No. ML051650002)
June 16, 2005	Summary of May 26, 2005 Telephone Conference Between the NRC and NMC Regarding Open and Confirmatory Items (Accession No. ML051680050)
June 16, 2005	Summary of May 28, 2005 Telephone Conference Between the NRC and NMC Regarding Draft Requests for Additional Information for PBNP (Accession No. ML051680452)
June 29, 2005	Final Update Information Regarding the PBNP LRA (Accession No. ML051890055)
June 29, 2005	Clarification to Information Regarding PBNP LRA (Accession No. ML051890064)
July 5, 2005	NMC Response to Request for Additional Information Regarding the PBNP LRA (Accession No. ML051940355)
July 7, 2005	Certification of the Minutes of the Plant License Renewal Subcommittee Meeting on the PBNP LRA, May 31, 2005 in Rockville, Maryland (Accession No. ML052150202)

July 8, 2005	Clarification to Information Regarding the PBNP LRA (Accession No. ML052020233)
July 15, 2005	Letter from Luis A. Reyes, EDO, to Graham B. Wallis, ACRS, Regarding the Response to Interim Report on the Safety Aspects of the PBNP LRA (G20050428) (Accession No. ML051860393)
July 15, 2005	Enclosure to response to Advisory Committee on Reactor Safeguards, NRC Action, Under the Reactor Oversight Process for the PBNP, Units 1 and 2 (G20050428) (Accession No. ML051860398)
July 19, 2005	Clarification to Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML052080144)
July 27, 2005	Summary of June 30, 2005 and July 8, 2005, Telephone Conferences Between NRC and NMC Regarding Confirmatory Items (Accession No. ML052100254)
August 12, 2005	NUREG-1437 Supplement 23, Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Supplement 23 Regarding Point Beach Nuclear Plant, Units 1 and 2, Final Report (Accession No. ML052230490)
August 23, 2005	Additional Information Regarding the PBNP LRA (TAC Nos. MC2099 and MC2100) (Accession No. ML052440350)
September 9, 2005	Point Beach Nuclear Plant, Units 1 and 2, NRC License Renewal Followup Inspection Report (05000266/2005015 (DRS), 05000301/2005015(DRS)) (Accession No. ML0525602640)
September 23, 2005	Docketing of Additional Information Pertaining to LRA of the PBNP, Units 1 and 2 (Accession Package No. ML052630524)
September 27, 2005	Summary of August 10, 2005 Telephone Conference Between NRC and NMC Concerning Comments to the PBNP, Units 1 and 2, Draft Safety Evaluation Report (Accession No. ML052700508)
October 1, 2005	Letter from Mr. P.T. Kuo, NRC, to Mr. Dennis L. Koehl, NMC, regarding the Safety Evaluation Report (SER) Related to the License Renewal of Point Beach Nuclear Plant, Units 1 and 2 (TAC Nos. MC2099 and MC2100) (Accession No. ML052760238)
November 18, 2005	Letter from Dr. Graham B. Wallis, ACRS, to the Honorable Nils J. Diaz, NRC Chairman, regarding the Report on the Safety Aspects of the License Renewal Application for the Point Beach Nuclear Plant Units 1 and 2 (Accession No. ML053250548)

APPENDIX C

REQUESTS FOR ADDITIONAL INFORMATION

Request for Additional Information (RAI)	Issuance Date	Response Date
Section 1: Introduction and General Discussion		
Section 2: Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results		
2.1 Scoping and Screening Methodology		
RAI 2.1-1	November 16, 2004	January 31, 2005
		March 15, 2005
		April 29, 2005
		July 19, 2005
RAI 2.1-2	November 16, 2004	January 31, 2005
RAI 2.1-3	November 16, 2004	January 31, 2005
		March 15, 2005
2.2 Plant Level Scoping Results		
2.3 Scoping and Screening Results: Mechanical Systems		
2.3.1 Reactor Vessel, Internals, and Reactor Coolant System		
2.3.1.1 Class 1 Piping/Components System		
RAI 2.3.1.1-1	November 17, 2004	December 21, 2004
2.3.1.2 Reactor Vessel		
RAI 2.3.1.2-1	November 17, 2004	December 21, 2004
2.3.1.3 Reactor Vessel Internals		
2.3.1.4 Pressurizer		
RAI 2.3.1.4-1	November 17, 2004	December 21, 2004
RAI 2.3.1.4-2	November 17, 2004	December 21, 2004
2.3.1.5 Steam Generators		
2.3.1.6 Non-Class 1 RCS Component Systems		
2.3.2 Engineered Safety Features		

Request for Additional Information (RAI)	Issuance Date	Response Date
2.3.2.1 Safety Injection System		
2.3.2.2 Containment Spray System		
2.3.2.3 Residual Heat Removal System		
2.3.2.4 Containment Isolation Components Systems		
2.3.3 Auxiliary Systems		
2.3.3.1 Chemical and Volume Control System		
2.3.3.2 Component Cooling Water System		
RAI 2.3.3.2-1	November 10, 2004	December 14, 2004
2.3.3.3 Spent Fuel Cooling System		
RAI 2.3.3.3-1	November 10, 2004	December 14, 2004
RAI 2.3.3.3-2	November 10, 2004	December 14, 2004
2.3.3.4 Waste Disposal System		
RAI 2.3.3.4-1	November 16, 2004	December 22, 2004
RAI 2.3.3.4-2	November 16, 2004	December 22, 2004
RAI 2.3.3.4-3	November 16, 2004	December 22, 2004
RAI 2.3.3.4-4	November 16, 2004	December 22, 2004
2.3.3.5 Service Water System		
RAI 2.3.3.5-1	November 10, 2004	December 14, 2004
RAI 2.3.3.5-2	November 10, 2004	December 14, 2004
RAI 2.3.3.5-3	November 10, 2004	December 14, 2004
RAI 2.3.3.5-4	November 10, 2004	December 14, 2004
RAI 2.3.3.5-5	November 10, 2004	December 14, 2004
2.3.3.6 Fire Protection System		
RAI 2.3.3.6-1	September 10, 2004	October 8, 2004
RAI 2.3.3.6-2	September 10, 2004	October 8, 2004
RAI 2.3.3.6-3	September 10, 2004	October 8, 2004
RAI 2.3.3.6-4	September 10, 2004	October 8, 2004
RAI 2.3.3.6-5	September 10, 2004	October 8, 2004

Request for Additional Information (RAI)	Issuance Date	Response Date
RAI 2.3.3.6-6	September 10, 2004	October 8, 2004
RAI 2.3.3.6-7	September 10, 2004	October 8, 2004
RAI 2.3.3.6-8	September 10, 2004	October 8, 2004
RAI 2.3.3.6-9	September 10, 2004	October 8, 2004
RAI 2.3.3.6-10	September 10, 2004	October 8, 2004
RAI 2.3.3.6-11	September 10, 2004	October 8, 2004
RAI 2.3.3.6-12	September 10, 2004	October 8, 2004
RAI 2.3.3.6-13	September 10, 2004	October 8, 2004
2.3.3.7 Heating Steam System - Within Scope of License Renewal for Criterion 2 Only		
RAI 2.3.3.7-1	November 10, 2004	December 14, 2004
2.3.3.8 Emergency Power System		
RAI 2.3.3.8-1	November 16, 2004	December 22, 2004
RAI 2.3.3.8-2	November 16, 2004	December 22, 2004
RAI 2.3.3.8-3	November 16, 2004	December 22, 2004
		February 7, 2005
RAI 2.3.3.8-4	November 16, 2004	December 22, 2004
RAI 2.3.3.8-5	November 16, 2004	December 22, 2004
2.3.3.9 Containment Ventilation System		
RAI 2.3.3.9	November 17, 2004	December 17, 2004
2.3.3.10 Essential Ventilation System		
RAI 2.3.3.10	November 17, 2004	December 17, 2004
RAI 2.3.3.10-1	December 17, 2004	January 17, 2005
2.3.3.11 Treated Water System - Within Scope of License Renewal for Criterion 2 Only		
RAI 2.3.3.11-1	November 10, 2004	December 14, 2004
RAI 2.3.3.11-2	November 10, 2004	December 14, 2004
2.3.3.12 Circulating Water System - Within Scope of License Renewal for Criterion 2 Only		
RAI 2.3.3.12-1	November 10, 2004	December 14, 2004
RAI 2.3.3.12-2	November 10, 2004	December 14, 2004

Request for Additional Information (RAI)	Issuance Date	Response Date
2.3.3.13 Fuel Handling System		
2.3.3.14 Plant Sampling System		
2.3.3.15 Plant Air System		
RAI 2.3.3.15-1	November 16, 2004	December 22, 2004
RAI 2.3.3.15-2	November 16, 2004	December 22, 2004
RAI 2.3.3.15-3	November 16, 2004	December 22, 2004
2.3.3.16 Containment Hydrogen Detectors and Recombiner System		
2.3.4 Steam and Power Conversion System		
2.3.4.1 Main and Auxiliary Steam System		
2.3.4.2 Feedwater and Condensate System		
RAI 2.3.4.2-1	November 16, 2004	December 22, 2004
RAI 2.3.4.2-2	November 16, 2004	December 22, 2004
RAI 2.3.4.2-3	November 16, 2004	December 22, 2004
RAI 2.3.4.2-4	January 10, 2005	January 26, 2005
		March 15, 2005
2.3.4.3 Auxiliary Feedwater System		
RAI 2.3.4.3-1	November 16, 2004	December 22, 2004
RAI 2.3.4.3-2	November 16, 2004	December 22, 2004
RAI 2.3.4.3-3	November 16, 2004	December 22, 2004
2.4 Scoping and Screening Results: Containments, Structures, and Component Supports		
RAI 2.4-1	January 26, 2005	February 25, 2005
RAI 2.4-2	January 26, 2005	February 25, 2005
		June 10, 2005
		June 29, 2005
RAI 2.4-3	January 26, 2005	February 25, 2005
RAI 2.4-4	January 26, 2005	February 25, 2005
RAI 2.4-5	January 26, 2005	February 25, 2005
RAI 2.4-6	January 26, 2005	February 25, 2005

Request for Additional Information (RAI)	Issuance Date	Response Date
RAI 2.4-7	January 26, 2005	February 25, 2005
RAI 2.4-8	January 26, 2005	February 25, 2005
RAI 2.4-9	January 26, 2005	February 25, 2005
RAI 2.4-10	January 26, 2005	February 25, 2005
RAI 2.4-11	January 26, 2005	February 25, 2005
RAI 2.4-12	January 26, 2005	February 25, 2005
RAI 2.4.11-1	September 10, 2004	October 8, 2004
2.5 Scoping and Screening Results: Electrical and Instrumentation and Controls		
RAI 2.5.1	November 18, 2004	January 25, 2005
Section 3: Aging Management Review Results		
3.1 Aging Management of Reactor Coolant System		
RAI 3.1.2-1	November 17, 2004	January 25, 2005
RAI 3.1.2-2	November 17, 2004	January 25, 2005
RAI 3.1.2-3	November 17, 2004	January 25, 2005
RAI 3.1.2-4	November 17, 2004	January 25, 2005
RAI 3.1.2-5	November 17, 2004	January 25, 2005
RAI 3.1-1	November 18, 2004	January 6, 2005
RAI 3.1-2	November 18, 2004	January 6, 2005
RAI 3.1-3	November 18, 2004	January 6, 2005
RAI 3.1-4	November 18, 2004	January 6, 2005
RAI 3.1-5	November 18, 2004	January 6, 2005
RAI 3.1-6	November 18, 2004	January 6, 2005
RAI 3.1.1-1	March 30, 2005	June 9, 2005
RAI 3.1.1-2	March 30, 2005	June 9, 2005
3.2 Aging Management of Engineered Safety Features		
RAI 3.2-1	July 30, 2004	August 30, 2004
RAI 3.2-2	July 30, 2004	August 30, 2004

Request for Additional Information (RAI)	Issuance Date	Response Date
3.3 Aging Management of Auxiliary Systems		
RAI 3.3-1	November 18, 2004	January 7, 2005
RAI 3.3-2	November 18, 2004	January 7, 2005
RAI 3.3-3	November 18, 2004	January 7, 2005
RAI 3.3-4	November 18, 2004	January 7, 2005
RAI 3.3-5	November 18, 2004	January 7, 2005
RAI 3.3-6	November 18, 2004	January 7, 2005
		March 15, 2005
RAI 3.3-7	March 31, 2005	April 29, 2005
		June 10, 2005
RAI 3.3.2.1.6-1	September 10, 2004	October 8, 2004
		March 15, 2005
3.4 Aging Management of Steam and Power Conversion System		
RAI 3.4-1	July 30, 2004	August 30, 2004
RAI 3.4-2	July 30, 2004	August 30, 2004
3.5 Aging Management of Containments, Structures, and Component Supports		
RAI 3.5-1	July 27, 2004	August 26, 2004
RAI 3.5-2	July 27, 2004	August 26, 2004
RAI 3.5-3	July 27, 2004	August 26, 2004
RAI 3.5-4	July 27, 2004	August 26, 2004
		March 15, 2005
		June 10, 2005
		July 8, 2005
RAI 3.5-5	July 27, 2004	August 26, 2004
		March 15, 2005
RAI 3.5-6	July 27, 2004	August 26, 2004
RAI 3.5-7	July 27, 2004	August 26, 2004
RAI 3.5-8	July 27, 2004	August 26, 2004

Request for Additional Information (RAI)	Issuance Date	Response Date
RAI 3.5-9	July 27, 2004	August 26, 2004
RAI 3.5-10	July 27, 2004	August 26, 2004
RAI 3.5-11	July 27, 2004	August 26, 2004
RAI 3.5-12	March 30, 2005	June 9, 2005
RAI 3.5-13	March 30, 2005	June 9, 2005
RAI 3.5-14	March 31, 2005	April 29, 2005
3.6 Aging Management of Electrical and Instrumentation and Controls		
RAI 3.6.2.1.1	November 18, 2004	January 25, 2005
RAI 3.6.2.1.2	November 18, 2004	January 25, 2005
RAI 3.6.2.1.3	November 18, 2004	January 25, 2005
		March 15, 2005
RAI 3.6.2.1.4	November 18, 2004	January 25, 2005
RAI 3.6.2.1.5	November 18, 2004	January 25, 2005
RAI 3.6.2.1.6	November 18, 2004	January 25, 2005
RAI 3.6.2.1.7	November 18, 2004	January 25, 2005
Section 4: Time Limited Aging Analysis		
4.1 Identification of Time-Limited Aging Analyses		
RAI 4.1.1-1	November 17, 2004	January 25, 2005
RAI 4.1.1-2	November 17, 2004	January 25, 2005
4.2 Reactor Vessel Irradiation Embrittlement		
RAI 4.2-1	September 23, 2004	September 10, 2004
		October 25, 2004
RAI 4.2-2	September 23, 2004	September 10, 2004
		October 25, 2004
4.3 Metal Fatigue		
4.3.1 Reactor Vessel Structural Integrity		
RAI 4.3.1	November 17, 2004	January 28, 2005

Request for Additional Information (RAI)	Issuance Date	Response Date
4.3.2 Reactor Vessel Internals Structural Integrity		
RAI 4.3.2.1	November 17, 2004	January 28, 2005
RAI 4.3.2.2	November 17, 2004	January 28, 2005
4.3.3 Control Rod Drive Mechanism Structural Integrity		
RAI 4.3.3	November 17, 2004	January 28, 2005
4.3.4 Steam Generator Structural Integrity		
RAI 4.3.4.1	November 17, 2004	January 28, 2005
RAI 4.3.4.2	November 17, 2004	January 28, 2005
RAI 4.3.4.3	November 17, 2004	January 28, 2005
4.3.5 Pressurizer Structural Integrity		
RAI 4.3.5.1	November 17, 2004	January 28, 2005
RAI 4.3.5.2	November 17, 2004	January 28, 2005
RAI 4.3.5.3	November 17, 2004	January 28, 2005
RAI 4.3.5.4	November 17, 2004	January 28, 2005
RAI 4.3.5.5	November 17, 2004	January 28, 2005
4.3.6 Reactor Coolant Pump Structural Integrity		
4.3.7 Pressurizer Surge Line Structural Integrity		
RAI 4.3.7	November 17, 2004	January 28, 2005
4.3.8 Pressurizer Spray Header Piping Structural Integrity		
RAI 4.3.8	November 17, 2004	January 28, 2005
4.3.9 USAS B31.1 Piping Structural Integrity		
4.3.10 Environmental Effects on Fatigue		
RAI 4.3.10.1	November 17, 2004	January 28, 2005
RAI 4.3.10.2	November 17, 2004	January 28, 2005
4.3.11 Containment Liner Plate Fatigue Analysis		
4.3.12 Spent Fuel Pool Liner Fatigue Analysis		
4.3.13 Crane Load Cycle Limits		
RAI 4.3.13-1	November 18, 2004	January 7, 2005

Request for Additional Information (RAI)	Issuance Date	Response Date
4.4 Fracture Mechanics Analysis		
4.4.1 Reactor Vessel Underclad Cracking		
4.4.2 Reactor Coolant Pump Flywheel Analysis		
RAI 4.4.2	November 17, 2004	January 25, 2005
4.4.3 Reactor Coolant Pump Casing Analysis (ASME Code Case N–481 Analysis)		
Section withdrawn		March 4, 2005
4.4.4 Reactor Coolant System Main Loop Piping Leak-Before-Break Analysis		
4.4.5 Pressurizer Surge Line Piping Leak-Before-Break Analysis		
4.4.6 Class 1 Accumulator Injection Line Piping Leak-Before-Break Analysis		
4.4.7 Class 1 RHR Line Piping Leak-Before-Break Analysis		
4.4.8 Component/Piping Subsurface Indication Analysis		
Section withdrawn		March 4, 2005
4.5 Loss of Preload		
RAI 4.5-1	July 27, 2004	August 26, 2004
		March 15, 2005
RAI 4.5-2	July 27, 2004	August 26, 2004
		March 15, 2005
4.6 Neutron Absorber		
RAI 4.6.1-1	March 29, 2005	April 1, 2005
RAI 4.6.1-2	March 29, 2005	April 1, 2005
RAI 4.6.1-3	March 29, 2005	April 1, 2005
4.7 Wear		
4.7.1 Bottom Mounted Instrumentation Thimble Tube Wear		
4.7.2 Containment Accident Recirculation Heat Exchanger Tube Wear		
Section withdrawn		March 4, 2005
4.8 Environmental Qualification		
Appendix B: Aging Management Programs and Activities		
B.1.1 Overview		

Request for Additional Information (RAI)	Issuance Date	Response Date
B.1.2 Method of Discussion		
B.1.3 Quality Assurance Program and Administrative Controls		
B.1.4 Operating Experience		
B.1.5 Aging Management Programs		
B.1.6 Time Limited Aging Analyses Aging Management Programs		
B.2 Aging Management Programs Correlation		
B.2.1 Aging Management Programs Details		
RAI B.2.1	March 30, 2005	July 5, 2005
B.2.1.1 ASME Section XI, Subsections IWB, IWC, and IWD Inservice Inspection Program		
B.2.1.2 ASME Section XI, Subsections IWE & IWL Inservice Inspection Program		
B.2.1.3 ASME Section XI, Subsections IWF Inservice Inspection Program		
B.2.1.4 Bolting Integrity Program		
RAI B.2.1.4-1	February 7, 2005	March 4, 2005
RAI B.2.1.4-2	February 7, 2005	March 4, 2005
		April 8, 2005
		July 19, 2005
RAI B.2.1.4-3	February 7, 2005	March 4, 2005
RAI B.2.1.4-4	February 7, 2005	March 4, 2005
RAI B.2.1.4-5	February 7, 2005	March 4, 2005
RAI B.2.1.4-6	February 23, 2005	March 15, 2005
B.2.1.5 Boraflex Monitoring Program		
RAI B.2.1.5-1	February 23, 2005	March 15, 2005
RAI B.2.1.5-2	February 23, 2005	March 15, 2005
RAI B.2.1.5-3	February 23, 2005	March 15, 2005
RAI B.2.1.5-4	February 23, 2005	March 15, 2005
B.2.1.6 Boric Acid Corrosion Program		
RAI B.2.1.6-1	November 17, 2004	January 25, 2005

Request for Additional Information (RAI)	Issuance Date	Response Date
B.2.1.7 Buried Services Monitoring Program		
RAI B.2.1.7-1	November 18, 2004	January 6, 2005
		March 15, 2005
RAI B.2.1.7-2	November 18, 2004	January 6, 2005
RAI B.2.1.7-3	November 18, 2004	January 6, 2005
B.2.1.8 Cable Condition Monitoring Program		
RAI B.2.1.8-1	December 21, 2004	January 21, 2005
		March 15, 2005
B.2.1.9 Closed-Cycle Cooling Water System Surveillance Program		
B.2.1.10 Fire Protection Program		
B.2.1.11 Flow-Accelerated Corrosion Program		
RAI B.2.1.11-1	March 30, 2005	April 8, 2005
		June 9, 2005
B.2.1.12 Fuel Oil Chemistry Control Program		
B.2.1.13 One-Time Inspection Program		
RAI B.2.1.13-1	September 16, 2004	October 15, 2004
B.2.1.14 Open-Cycle Cooling (Service) Water System Surveillance Program		
B.2.1.15 Periodical Surveillance and Preventive Maintenance Program		
B.2.1.16 Reactor Coolant System Alloy 600 Inspection Program		
RAI 2.1.16-1	November 17, 2004	January 25, 2005
RAI 2.1.16-2	November 17, 2004	January 25, 2005
B.2.1.17 Reactor Vessel Internals Program		
B.2.1.18 Reactor Vessel Surveillance Program		
RAI B2.1.18-1	November 17, 2004	January 25, 2005
B.2.1.19 Steam Generator Integrity Program		
B.2.1.20 Structures Monitoring Program		
B.2.1.21 Systems Monitoring Program		

Request for Additional Information (RAI)	Issuance Date	Response Date
B.2.1.22 Tank Internal Inspection Program		
RAI B.2.1.22-1	November 18, 2004	January 6, 2005
RAI B.2.1.22-2	November 18, 2004	January 6, 2005
RAI B.2.1.22-3	November 18, 2004	January 6, 2005
RAI B.2.1.22-4	November 18, 2004	January 6, 2005
B.2.1.23 Thimble Tube Inspection Program		
RAI B.2.1.23-1	November 17, 2004	January 25, 2005
B.2.1.24 Water Chemistry Control Program		
B.3 TLAA Support Activities		
B.3.1 Environmental Qualification Program		
B.3.2 Fatigue Monitoring Program		
B.3.3 Pre-Stressed Concrete Containment Tendon Surveillance Program		
RAI B.3.3-1	January 12, 2005	January 28, 2005
		March 15, 2005
RAI B.3.3-2	January 12, 2005	January 28, 2005
		March 15, 2005
RAI B.3.3-3	January 12, 2005	January 28, 2005
		March 15, 2005
RAI B.3.3-4	January 12, 2005	January 28, 2005
		March 15, 2005
Section withdrawn		March 15, 2005

APPENDIX D

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APPENDIX E

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This appendix contains a listing of references used in preparation of the Safety Evaluation Report prepared during the review of the license renewal application for Point Beach Nuclear Plant Units 1 and 2, Docket Numbers 50-266 and 50-301 respectively.

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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-1839
2. TITLE AND SUBTITLE Safety Evaluation Report Related to the License Renewal of Point Beach Nuclear Plant, Units 1 and 2	3. DATE REPORT PUBLISHED MONTH: December YEAR: 2005 4. FIN OR GRANT NUMBER
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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

Docket numbers 50-301, 50-266.

11. ABSTRACT *(200 words or less)*

This safety evaluation report (SER) documents the technical review of the Point Beach Nuclear Plant (PBNP) Units 1 and 2 license renewal application (LRA) by the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff). By letter dated February 25, 2004, Nuclear Management Company, LLC (NMC or the applicant) submitted the LRA for PBNP in accordance with Title 10, Part 54, of the Code of Federal Regulations (10 CFR Part 54). NMC is requesting renewal of the operating licenses for PBNP Units 1 and 2 (Facility Operating License Numbers DPR-24 and DPR-27, respectively) for a period of 20 years beyond the current expiration dates of midnight, October 5, 2010, for Unit 1 and midnight, March 8, 2013, for Unit 2.

The PBNP units are located about 30 miles SE of Green Bay and about 90 miles NNE of Milwaukee in east central Wisconsin (Manitowoc County) on the west shore of Lake Michigan. The NRC issued the construction permit for PBNP Unit 1 on July 19, 1967, and for Unit 2 on July 25, 1968. The operating licenses were issued by the NRC on October 5, 1970, for Unit 1 and March 8, 1973 for Unit 2. The PBNP consists of two Westinghouse pressurized light-water moderated and cooled system units originally designed to generate 1518.5 megawatt thermal (MWt), or approximately 523.8 megawatt electric (MWe). Each unit has undergone a low pressure turbine retrofit modification which increases the unit design output to 537,960 kWe. In 2003, a measurement uncertainty recapture power uprate was performed increasing each unit's rated thermal power level to 1540 MWt.

This SER presents the status of the staff's review of information submitted to the NRC through August 23, 2005, the cutoff date for consideration in the SER. The staff identified open items and confirmatory items that had to be resolved before the staff could make a final determination on the application. Sections 1.5 and 1.6 of this report summarize these items and their resolutions. Section 6 presents the staff's final conclusion on the review of the PBNP application.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*	13. AVAILABILITY STATEMENT
10 CFR 54 Part 54 license renewal Point Beach PBNP scoping and screening aging management time-limited aging analysis TLAA safety evaluation report SER	unlimited 14. SECURITY CLASSIFICATION *(This Page)* unclassified *(This Report)* unclassified 15. NUMBER OF PAGES 16. PRICE

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