In LRA Amendment 1, dated December 18, 2007, the applicant revised LRA Section B.1.20, "Metal Enclosed Bus Inspection," Program Description, second paragraph, and the enhancements as follows:

> Program Description
> Inspections of the metal enclosed bus (MEB) include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program for external surfaces of the bus enclosure assemblies. The internal portions of the MEB will be inspected for foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation or insulators are inspected for degradation leading to reduced insulation resistance (IR). The bus insulation will be inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The internal bus supports or insulators will be inspected for structural integrity and signs of cracks and corrosion. These inspections include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required.
>
> Enhancements
> Attributes Affected: 3. Parameters Monitored or Inspected; 4. Detection of Aging Effects; 6. Acceptance Criteria
> Revise appropriate procedures to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material.
>
> Attributes Affected: 4. Detection of Aging Effects
> Revise appropriate procedures to inspect bolted connections at least once every five years if only performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation.

The applicant also revised LRA Sections A.2.1.19 and A.3.1.19, Metal Enclosed Bus Inspection Program, second paragraph, as follows:

> Inspections of the metal enclosed bus (MEB) include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program for external surfaces of the bus enclosure assemblies. The internal portions of the MEB will be inspected for foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation or insulators are inspected for degradation leading to reduced insulation resistance (IR). These inspections include visual inspections, as well as quantitative

measurements, such as thermography or connection resistance measurements, as required.

In addition, LRA Sections A.2.1.19 and A.3.1.19, Metal Enclosed Bus Inspection Program, third paragraph, second bullet was revised as follows.

> Revise appropriate procedures to inspect bolted connections at least once every five years if only performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements.

During the license renewal regional inspection, the staff questioned the completeness of acceptance criteria for the internal inspection portion of the program procedures. The applicant agreed to revise the inspection procedures to include more complete acceptance criteria and amended the LRA.

In LRA Amendment 3, dated March 24, 2008, the applicant revised LRA Section A.2.1.19, Metal-Enclosed Bus Inspection Program, third paragraph to add the following enhancement:

> Revise acceptance criteria of appropriate procedures for MEB internal visual inspection inspections to include the absence of indication of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct.

The applicant also revised LRA Section A.3.1.19, Metal-Enclosed Bus Inspection Program, third paragraph to the following enhancement.

> Revise acceptance criteria of appropriate procedures for MEB internal visual inspection inspections to include the absence of indication of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct.

In addition, the applicant revised LRA Section B.1.20, Metal Enclosed Bus Inspection Program, Enhancements, as follows.

> 6. Acceptance Criteria
>
> Revise the acceptance criteria for MEB internal visual inspections to include the absence of indication of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indication of moisture intrusion into the duct.

The staff finds the applicant's response acceptable. With the revisions described above, the applicant's LRA Section B.1.20, FSAR supplements, program basis documents, and plant implementation procedures are consistent with each other. The staff also finds the enhancement acceptable because after enhancements the applicant's MEB program are consistent with the GALL Report XI.E4. The inspection methods as described are consistent with those in the GALL Report AMP XI.E4. The acceptance criteria have been revised to be more complete as agreed to during the regional inspection. The staff

verified in letters dated December 18, 2007, and March 24, 2008, that the applicant revised LRA and UFSAR supplement as described above.

Operating Experience. LRA Section B.1.20 states that a comparison of techniques for the cleaning and inspection of metal-enclosed buses at IP2 and IP3 was performed to develop a site-wide program procedure with input from NRC Information Notice 2000-014. The applicant also stated that comparison of program techniques and use of industry findings in the development of site-wide procedures assure continued program effectiveness in managing aging effects for passive components.

The staff noted that the applicant developed a site-wide program based on lessons learned from industry findings and the staff generic communications. The staff finds this information provide evidence to support the conclusion that aging will be managed adequately so that structure and component intended functions will be maintained during the period of extended operation.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.19 and A.3.1.19, the applicant provided the UFSAR supplement for the Metal-Enclosed Bus Inspection Program. The staff reviewed these sections and the amendments as described above, and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.19 and A.3.1.19, the applicant has committed to enhance the program prior to entering the period of extended operation (Commitment 19).

Conclusion. On the basis of its audit and review of the applicant's Metal-Enclosed Bus Inspection Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the program is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.12 Oil Analysis Program

Summary of Technical Information in the Application. LRA Section B.1.26 describes the existing Oil Analysis Program as consistent with GALL AMP XI.M39, "Lubricating Oil Analysis," with exception and enhancements.

The Oil Analysis Program maintains oil systems free of contaminants (primarily water and particulates) to preserve an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951, and ASTM D96. Water, particle concentration and viscosity acceptance criteria are based on industry standards supplemented by manufacturers' recommendations.

Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. These templates are based on EPRI preventive maintenance (PM) bases documents TR-106857 Volumes 1 through 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure. The One-Time Inspection Program includes inspections planned to verify the effectiveness of the Oil Analysis Program.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Oil Analysis Program and basis documents for consistency with GALL AMP XI.M39. Details of the staff's audit of this AMP are documented in the Audit Report. As documented in the report, the staff found that the Oil Analysis Program element "scope of program," is consistent with the respective element in GALL AMP XI.E4. Because this element is consistent with the GALL Report element, the staff finds that it is acceptable.

The staff reviewed the exception and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

In the program basis document the applicant states that the Oil Analysis Program includes sampling and analysis of lubricating oil for components within the scope of license renewal and subject to aging management review, that are exposed to lubricating oil, for which pressure boundary integrity or heat transfer is required for the component to perform its intended function. The staff confirmed that the specific components for which the oil analysis program manages aging are identified and the lubricating oil to which these components are exposed is included in the oil analysis program.

In the program basis document, the applicant states that oil systems within the scope of the program are monitored to detect and control abnormal levels of contaminants (primarily water and particulates), thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. In response to staff's inquiries regarding detection of out-of-specification conditions, the applicant stated that the results of lube oil analyses are reviewed by the predictive maintenance group to determine if oil is suitable for continued use until the next scheduled sampling or scheduled oil change. Oil analysis data sheets are provided by an offsite vendor with current and historical analysis results. The data are reviewed to evaluate unusual trends. When degraded conditions are indicated, the predictive maintenance group will take appropriate actions to check the validity of the data and issue a condition report with recommended corrective actions.

The staff confirmed that preventive sampling and analysis activities were included in the implementing procedures.

In Amendment 1 to the LRA, dated December 18, 2007, the applicant revised LRA Sections B.1.26, A.2.1.25 and A.3.1.25 regarding determination of oil sampling frequencies. The applicant stated that oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. The templates are based on EPRI PM bases documents TR-106857 Volumes 1 through 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure. The staff determined that the sampling frequencies are consistent with current industry standards, and are consistent with the plant technical specifications, where applicable. The sampling frequencies will provide for timely detection of lubricating oil contamination, and will allow corrective actions to be taken, as needed, prior to the loss of intended function. On this basis, the staff finds these sampling frequencies acceptable.

Exception. In the LRA, the applicant took the following exception to the GALL Report program element "parameters monitored or inspected": "NUREG-1801 requires determination of flash point for components that do not have regular oil changes to verify the oil is suitable for continued use. IP does not determine flash point for systems that are not potentially exposed to hydrocarbons. For lubricating oil systems potentially exposed to hydrocarbons, fuel dilution testing is performed in lieu of flash point testing."

The staff noted that the discussion of this exception in LRA Section B.1.26 includes a footnote, which states the following:

> While it is important from an industrial safety perspective to monitor flash point, it has little significance with respect to the effects of aging. Analyses of filter residue or particle count, viscosity, total acid/base (neutralization number), water content, fuel dilution, and metals content provide sufficient information to verify the oil is suitable for continued use. IPEC performs a fuel dilution test in lieu of flash point testing on emergency diesel generators and IP3 Appendix R diesel generator lubricating oils. This test accomplishes the same goal as the flash point test but is more prescriptive. The fuel dilution test determines the percent by volume of fuel and water. The analysis can determine the cause of the change in flash point without having to conduct additional tests. Corrective actions, if required, could be implemented on a timelier basis. For oil systems not associated with internal combustion engines, lubricating oil flash point change is unlikely.

The staff noted that the GALL Report AMP XI.M39, states that for components with periodic oil changes in accordance with manufacturer's recommendations, a particle count and check for water are performed to detect evidence of abnormal wear rates, contamination by moisture, or excessive corrosion. Section XI.M39, further states that for components that do not have regular oil changes, viscosity, neutralization number, and flash point are also determined to verify the oil is suitable for continued use.

During an audit, the staff asked the applicant to provide a technical justification for this exception (Audit Item 69). By letter dated March 24, 2008, the applicant referred to the technical basis provided in LRA section B.1.26, exception footnote 1, which states that fuel dilution

testing is performed in lieu of flash point testing for lubricating oil systems potentially exposed to hydrocarbons. IP2 and IP3 perform a fuel dilution test in lieu of flash point testing on emergency diesel generators and IP3 Appendix R diesel generator lubricating oils.

The applicant further stated that there are two factors that affect the flash point of the oil: the addition of fuel that would lower the flash point or the addition of water that would raise the flash point. The fuel dilution test determines the percent by volume of fuel and the water content test determines the percent by volume of water. By determining the percent by volume of both fuel and water, the analysis can determine the expected change in flashpoint. While it is important from an industrial safety perspective to monitor flash point, it has little significance with respect to the effects of aging. Analyses of filter residue or particle count, viscosity, total acid/base (neutralization number), water content, fuel dilution, and metals content provide sufficient information to verify the oil is suitable for continued use. For oil systems not associated with internal combustion engines, lubricating oil flash point change is unlikely.

The staff noted that the GALL Report AMP XI.M39 recommends determination of flash point for components that do not have regular oil changes to verify that the oil is suitable for continued use. The applicant performs fuel dilution testing in lieu of flash point determination on lubricating oil systems, such as the emergency diesel generators and the Appendix R diesel, that are potentially exposed to hydrocarbons. The staff reviewed the applicants responses and determined that the performance of fuel dilution testing on lubricating oil systems that are potentially exposed to hydrocarbons will provide for timely detection of lubricating oil degradation or contamination, and will allow corrective actions to be taken, as needed, prior to the loss of intended function. Therefore, the staff concluded that this exception is consistent with the recommendations in the GALL Report and is acceptable.

Enhancement 1. In the LRA, and in Amendment 1 to the LRA, dated December 18, 2007, the applicant committed to implement the following enhancement to program elements "preventive actions," "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions": "[f]ormalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The program will specify corrective actions in the event acceptance criteria are not met."

The enhancement is necessary to ensure that administrative controls for preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria are in place for all components included in the scope of the oil analysis program.

The staff determined that the applicant's enhancement will add routine preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the oil analysis program. The screening process is supplemented with detailed analysis in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951, and ASTM D96. Water, particle concentration, and viscosity acceptance criteria are based on industry standards supplemented by manufacturers' recommendations. The preliminary oil screening process is, therefore, consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program element "parameters monitored or inspected": "IP2: Revise appropriate procedures to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators."

The enhancement is necessary to ensure that administrative controls for sampling and analysis of lubricating oil are in place for all components included in the scope of the oil analysis program. Program activities for sampling and analysis of lubricating oil will be consistent for all diesel generators on the site. The enhancement will ensure that lubricating oil sampling and analysis is included for all components included in the scope of the oil analysis program.

The staff determined that the applicant's enhancement will add routine sampling and analysis of lubricating oil for all diesel generators on the site which is consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program element "parameters monitored or inspected": "[r]evise appropriate procedures to sample and analyze generator seal oil and turbine hydraulic control oil (electrohydraulic fluid)."

The enhancement is necessary to ensure that administrative controls for sampling and analysis of generator seal oil and turbine hydraulic control oil (electrohydraulic fluid). The enhancement will ensure that lubricating oil sampling and analysis is included for all components included in the scope of the oil analysis program.

The staff determined that the applicant's enhancement will add routine sampling and analysis of generator seal oil and turbine hydraulic control oil (electrohydraulic fluid). The enhancement will ensure that lubricating oil is sampled and analyzed for all components on the site within the scope of the oil analysis program which is consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Enhancement 4. In the LRA and in Amendment 1 to the LRA, dated December 18, 2007, the applicant committed to implement the following enhancement to program element "monitoring and trending": "[f]ormalize trending of preliminary oil screening results as well as data provided from independent laboratories."

The enhancement is necessary to ensure that administrative controls for monitoring and trending of preliminary oil screening results and data from independent laboratory analyses are in place for all components included in the scope of the oil analysis program.

The staff determined that the applicant's enhancement will add formalized routine monitoring and screening of preliminary oil screening results and data from independent laboratory analyses for all components included in the scope of the oil analysis program. The screening process is supplemented with detailed analysis in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951, and ASTM D96. Water, particle concentration, and viscosity acceptance criteria are based on industry standards supplemented by manufacturers' recommendations. The formalized monitoring and trending of the results of the preliminary oil screening process is, therefore, consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Operating Experience. LRA Section B.1.26 states that analysis of oil samples taken in 1999 through 2006 from the containment spray pump motors showed lube oil in these motors within normal tolerances and satisfactory for continued use. Absence of particulates in a routine sampling program indicates a lack of corrosion, thus proving that the program effectively manages aging effects. Absence of contaminants indicates that the program effectively preserves an environment not conducive to loss of material, cracking, or fouling.

Analysis of an oil sample from a safety injection pump in April 2001 revealed moderate amounts of particulate and contaminates. Analysis of an oil sample from a reactor coolant pump lower bearing in November 2002 indicated a high particulate level. In each case, the lube oil for these pumps was replaced as a priority. Use of warning level indicators to direct corrective actions prior to equipment degradation proves that the program effectively manages aging effects.

Oil analysis results for EDG samples in April and May 2002 indicated increasing metal wear concentrations. IP3 diesel fire pump engine crankcase oil analysis results in June 2003 indicated a trend of elevated metal wear. In each case, the lube oil was replaced and appropriate corrective actions taken. Total acid numbers and viscosity levels from oil samples from service water pump motors in 2006 met warning levels. A 2006 sample of lube oil from a safety injection pump motor also indicated a high total acid number. Because of these data, the motor lube oil was replaced prior to component degradation. Use of warning level indicators to initiate corrective actions prior to equipment degradation assures program effectiveness in managing aging effects.

In June 2006, the applicant compared practices for oil analysis among all Entergy Nuclear Northeast sites and developed an action plan to establish common oil sampling frequencies and analysis techniques based on best practices among the sites. Comparison of program techniques and development of fleet-standard practices assures continued program effectiveness in managing aging effects for passive components.

The staff's review of operating experience documented in the program basis document indicates that this program has been effective in managing aging effects.

The staff confirmed that the "operating experience" program element satisfies the criterion in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.25 and A.3.1.25, the applicant provided the UFSAR supplement for the Oil Analysis Program.

In Amendment 1 to the LRA, Attachment 1, Audit Item 166, dated December 18, 2007, the applicant revised the first paragraph of Section A.2.1.25 and the first paragraph of Section A.3.1.25 as follows:

> The Oil Analysis Program is an existing program that maintains oil systems free of contaminants (primarily water and particulates) thereby preserving an environment that is not conducive to loss of material, cracking, or fouling. Activities include sampling and analysis of lubricating oil in accordance with industry standards such as ISO 4406, ASTM D445, ASTM D4951 and ASTM D96. Water, particle concentration and viscosity acceptance criteria are based on industry standards supplemented by manufacturer's recommendations.

In Amendment 1 to the LRA, dated December 18, 2007, the applicant revised the second paragraph of Sections A.2.1.25 and A.3.1.25 as follows:

> Oil analysis frequencies for IP2 and IP3 equipment are based on Entergy templates with technical basis justifications. Procedure EN-DC-335, "PM Bases Template", is based on EPRI PM bases documents TR-106857 volumes 1 thru 39 and TR-103147. Each template contains sections describing failure location and cause, progression of degradation to failure, fault discovery and intervention, task content and task objective. From information in these sections, frequencies are selected for the components managed by the Oil Analysis Program to mitigate failure.

In Amendment 1 to the LRA, dated December 18, 2007, the applicant revised the fourth paragraph of Section A.2.1.25 as follows:

> The Oil Analysis Program will be enhanced to include the following.
>
> - Revise appropriate procedures to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with oil analysis for other site diesel generators.
> - Revise appropriate procedures to sample and analyze generator seal oil and turbine hydraulic control oil (electrohydraulic fluid).
> - Formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The program will specify corrective actions in the event acceptance criteria are not met.
> - Formalize trending of preliminary oil screening results as well as data provided from independent laboratories.

In Amendment 1 to the LRA, dated December 18, 2007, the applicant revised the fourth paragraph of Section A.3.1.25 as follows:

> The Oil Analysis Program will be enhanced to include the following.
>
> - Revise appropriate procedures to sample and analyze generator seal oil and turbine hydraulic control oil (electrohydraulic fluid).
> - Formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of the program. The program will specify corrective actions in the event acceptance criteria are not met.
> - Formalize trending of preliminary oil screening results as well as data provided from independent laboratories.

The staff reviewed these sections and determines that the information in the UFSAR supplement, as amended, is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.25 and A.3.1.25, the applicant has committed to enhance the program prior to entering the period of extended operation (Commitment 18).

Conclusion. On the basis of its audit and review of the applicant's Oil Analysis Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. In addition, the staff reviewed the exception and its technical justification and determines that the program is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.13 Reactor Vessel Surveillance Program

Summary of Technical Information in the Application. LRA Section B.1.32 describes the existing Reactor Vessel Surveillance Program as consistent with GALL AMP XI.M31, "Reactor Vessel Surveillance," with enhancement.

The Reactor Vessel Surveillance Program manages reduction in fracture toughness of reactor vessel beltline materials to maintain the pressure boundary function of the reactor pressure vessel through the period of extended operation. The program, based on ASTM E-185, "Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels," as required by 10 CFR Part 50, Appendix H, evaluates radiation damage shown by pre- and post-irradiation testing of Charpy V-notch and tensile specimens. The rate at which these specimens accumulate radiation damage will be higher than that of the vessel because the specimens are closer to the core than the vessel itself.

Under the Reactor Vessel Integrity Program, reports submitted as required by 10 CFR Part 50, Appendix H include a capsule withdrawal schedule, a summary report of capsule withdrawal and test results, and, if needed, a technical specification change for pressure-temperature limit curves. The program, which meets ASTM E-185 recommendations and complies with 10 CFR Part 50, Appendix H, evaluates radiation damage shown by pre- and post-irradiation testing of Charpy V-notch and tensile specimens from the most limiting plate in the core region of the reactor vessel (RV).

Staff Evaluation. During its review, the staff confirmed the applicant's claim of consistency with the GALL Report. The staff reviewed the enhancements to determine whether the AMP, with the enhancements, remained adequate to manage the aging effects for which it is credited.

The Reactor Vessel Surveillance Program is identified as consistent with the program described in GALL Report, Section XI.M31, "Reactor Vessel Surveillance," with enhancements. The enhancements are: (1) to withdraw and test a standby capsule to cover the peak reactor vessel fluence that is expected through the end of the period of extended operation; and (2) to revise procedures to require that tested and untested specimens from all capsules pulled from the reactor vessel be maintained in storage.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement. In the LRA, the applicant committed to implement the following enhancement:

> The specimen capsule withdrawal schedules will be revised to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation.
>
> Appropriate procedures will be revised to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.

In Commitment 22, the applicant stated that it will revise the specimen capsule withdrawal schedules for IP2 and IP3 to withdraw and test a standby capsule to cover the peak RV neutron fluence expected through the end of the period of extended operation.

The withdrawal schedules will be submitted as required by 10 CFR Part 50, Appendix H, Section III.B.3.

In response to the staff's RAI B.1.1.32-1, the applicant provided the lead factors for each standby capsule, the materials available to be tested in each capsule, and the date for capsule withdrawal to ensure that the neutron fluence of the surveillance capsule will be equal or greater than the peak RV neutron fluence through the end of the period of extended operation. The response by the applicant is contained in their letter dated November 28, 2007.

Indian Point Nuclear Generating Unit No. 2 has three remaining capsules with lead factors of 1.2. The capsules contain surveillance test specimens from plates B2002-1, B2002-2 and B2002-3 and correlation monitor material. The lead factor is the ratio of the neutron fluence of the capsule to the neutron fluence of the reactor vessel. Therefore, the IP2 capsules will receive 20 percent more neutron fluence than the IP2 RV.

To ensure that the neutron fluence of the surveillance capsule will be equal to or greater than the peak RV neutron fluence through the end of the period of extended operation, at least one capsule will remain in the RV until approximately 40 effective full power years (EFPY). This burnup should be attained approximately 8 years prior to the end of the period of extended operation or around 2025.

Indian Point Nuclear Generating Unit No. 3 has three remaining capsules with lead factors of 1.52. Capsules W and U have surveillance test specimens from plates B2803-3 and B2802-1 and weld metal. Capsule V has surveillance test specimens from plate B2803-3 material, weld

metal, ASTM reference material and weld heat affected zone material. Since the lead factor is 1.52, the IP3 capsules will receive 52 percent more neutron fluence than the IP3 RV.

To ensure that the neutron fluence of the surveillance capsule will be equal to or greater than the peak RV neutron fluence through the end of the period of extended operation, a capsule must remain in the RV until approximately 32 EFPY. This burnup should be attained approximately 16 years prior to the end of the period of extended operation or around 2019.

The staff finds that the testing of the surveillance capsules in accordance with the proposed schedule provides reasonable assurance that the neutron-induced embrittlement in low alloy steel RV base metals and their associated welds will be adequately monitored during the extended period of operation. Additionally, the staff finds that the applicant's Reactor Vessel Surveillance Program complies with the requirements of the 10 CFR Part 50, Appendix H.

Operating Experience. LRA Section B.1.32 states that an updated RV surveillance capsule withdrawal schedule for IP2 was submitted to the staff in November 2004. Information from the surveillance program throughout the IP2 operating history was included in this request to change the previous schedule. The staff determined that the new withdrawal schedule met the 1982 Edition of ASTM E-185 criteria and complied with 10 CFR Part 50, Appendix H. Review of the surveillance requirements against industry standards, confirmed through staff oversight, assures continued program effectiveness in managing reduction in fracture toughness for RV beltline materials.

A summary of IP3 surveillance capsule exposure was prepared in a November 2003 neutron fluence evaluation for the unit's power uprate. This evaluation will be used to project the neutron exposure of the reactor vessel for future operating periods at the uprated power level. The surveillance capsule lead factors in this calculation will be the basis for development of future capsule withdrawal schedules. Review of the surveillance program due to changes from the power uprate assures continued program effectiveness in managing reduction in fracture toughness for reactor vessel beltline materials.

The staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.31 and A.3.1.31, the applicant provided the UFSAR supplement for the Reactor Vessel Surveillance Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.31 and A.3.1.31, the applicant has committed to enhance the program prior to entering the period of extended operation (Commitment 22).

Conclusion. On the basis of its review of the applicant's Reactor Vessel Surveillance Program, the staff determined that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concluded that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained

consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concluded that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.14 Steam Generator Integrity Program

Summary of Technical Information in the Application. LRA Section B.1.35 describes the existing Steam Generator Integrity Program as consistent with GALL AMP XI.M19, "Steam Generator Tube Integrity," with enhancement.

In the industry, steam generator (SG) tubes have experienced degradation from corrosion phenomena (e.g., PWSCC, outside diameter SCC, intergranular attack, pitting, and wastage) with other mechanically-induced phenomena (e.g., denting, wear, impingement damage, and fatigue). NDE techniques detect defective tubes that must be removed from service or repaired in accordance with plant technical specifications. The Steam Generator Integrity Program monitors and maintains secondary side component integrity. The program defines inspection and maintenance schedules, scope of work, and methods. The Steam Generator Integrity Program is consistent with NEI 97-06, "Steam Generator Program Guidelines."

Staff Evaluation. During its review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff reviewed the program elements of the Steam Generator Integrity Program to verify consistency with GALL AMP XI.M19. Based on the staff's review, the staff determined that Steam Generator Integrity elements "scope of program," "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.M19. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement. In the LRA, the applicant committed to implement the following enhancement program element "monitoring and trending": "[r]evise appropriate procedures to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated."

The applicant has committed to enhancing the program by requiring that the results of the condition monitoring assessment be compared to the operational assessment performed for the prior cycle with the differences evaluated. The operational assessment is performed at the completion of an inspection to demonstrate that SG tube integrity will be maintained during the up-coming operating cycle. It predicts what tube degradation will occur during operation, until the next planned inspection, and evaluates SG tube structural integrity and leakage integrity for that predicted level of degradation. The condition monitoring assessment is performed with as-found tube degradation data on a defect-specific basis, to demonstrate compliance with integrity criteria by the comparing the NDE measurements with calculated burst and leakage integrity limits. Calculated integrity limits, including consideration for appropriate uncertainties, burst and leak analytical correlations, material properties, NDE technique, and analyst uncertainties are provided in the degradation assessment report.

The staff agrees that this comparison and evaluation is an important attribute of an acceptable Steam Generator Integrity Program that should be performed and will result, long term, in a more robust program. The enhancement will be consistent with the guidance in NEI 97-06, "Steam Generator Program Guidelines," which endorses the EPRI "Steam Generator Integrity Assessment Guideline," (EPRI TR 107621). The EPRI guidelines state that condition monitoring results are to be evaluated with respect to the previous operational assessment and if the operational assessment did not bound the condition monitoring, then an analysis, in accordance with the plant corrective action program, shall be performed. Since these guidelines are consistent with the GALL Report, the staff finds that this enhancement is acceptable.

In RAI 3.1.2.2.14-1, dated December 7, 2007, the staff requested that the applicant provide additional details on the SG secondary side inspections performed on the feedwater inlet rings for each unit, to monitor for wear and loss of material due to flow accelerated corrosion.

In its response, by letter dated January 4, 2008, the applicant provided the following information. The IP2 SGs were replaced in 2000. The feedwater rings in the replacement SGs are not scheduled to be inspected until 2010. This planned inspection will be for two of the four SGs. The acceptance criteria for the inspection are the absence of any unusual conditions. Any conditions that do not meet this criterion will require further evaluation. This inspection frequency and criteria are acceptable based on the relatively short operating time of the new SGs and that the Steam Generator Integrity Program is implemented in accordance with NEI 97-06, "Steam Generator Program Guidelines," which includes inspections to assure secondary side component integrity.

The IP3 SGs were replaced in 1989. Since that time there have been 5 different inspections of all or some of the feedwater rings: in 1992 all 4 SGs were inspected, in 1997 SG 34, in 1999 SG 33, in 2001 SG 32, and in 2007 SGs 31 & 32. The scope of the inspections performed in 1997 through 2007 consisted of a visual exam of the outer diameter of the ring and a fiberscope inspection of the inner diameter of 5 selected J-nozzles (out of 36 total) and the feedwater ring tee. The next feedwater ring inspection for IP3 is planned for 2 SGs in 2013. No anomalies were noted in the prior inspections other than the appearance of minor washed out areas on the exterior of the feedwater ring beneath the outlets of the J-nozzles. The feedwater entering the steam generators exits the J-nozzles welded to the feedwater ring such that the discharge is directed downward towards the exterior of the feedwater ring. The feedwater ring is a carbon steel pipe that has a thin oxide film on the exterior surface. The flow from the J-nozzles prevents this oxide buildup giving the appearance of washed out areas where this feedwater impact occurs. Visual inspections of these washed out areas did not identify any loss of material on the feedwater ring.

Based on the applicant's response to the RAI describing the secondary side inspections performed to detect feedwater ring degradation, the staff finds the applicant's response to the RAI 3.1.2.2.14-1 acceptable. The staff's concern in RAI 3.1.2.2.14-1 is resolved.

Operating Experience. LRA Section B.1.35 states that IP2 SGs replaced in December 2000 began operating at uprated power levels in November 2004. IP3 SGs replaced in 1989 began operating at uprated power levels in April 2005.

A March 2003 IP3 SG degradation assessment per NEI 97-06 Revision 1 and the EPRI PWR Steam Generator Examination Guidelines Revision 5 (EPRI TR-107569) summarized the inspection results of IP3 replacement SGs since their installation in refueling outage 3R7 (1989), compared them to industry operating experience, and described a refueling outage 3R12 (2003) inspection plan based on this input. Use of plant-specific and industry operating experience and industry guidance in the development of an inspection plan assures program effectiveness in managing aging effects for passive components.

All indications from inspections of the IP3 SGs in March 2003 (refueling outage 3R12) were below calculated integrity limits in the pre-outage degradation assessment. During these refueling outage inspections, the staff evaluated the SG integrity assessment program and compared it to the staff-accepted guidance of EPRI "PWR Steam Generator Examination Guidelines," Revision 5 (EPRI TR-107569). To evaluate implementation of the SG assessment program, the staff witnessed SG tube testing and secondary side inspection processes and made no significant findings. Confirmation of program compliance with established standards and regulations assures effective program management of passive component aging.

The applicant revised the IP2 program procedure in June 2005 to incorporate the results of the September 2004 INPO Steam Generator Review Visit and the IP3 program procedure in July 2005 to incorporate the latest EPRI guidelines. Review of existing practices by industry groups, implementation of process improvements, and incorporation of industry guidelines assure continued program effectiveness in managing aging effects for passive components.

An INPO-assisted self-assessment of the IP2 and IP3 SG programs in September 2004 generated actions that led to program improvement in several key areas. Detection of program weaknesses and subsequent corrective actions assure continued program effectiveness in managing loss of component material.

An IP2 SG degradation assessment in April 2006 per NEI 97-06 Revision 1 and the EPRI TR-107569 summarized the inspection results of IP2 replacement SGs since their installation in December 2000, compared the results to industry operating experience, and listed a refueling outage 2R17 (2006) inspection plan based on this input. Use of plant-specific operating experience, industry operating experience, and industry guidance in the development of an inspection plan assures continued program effectiveness in managing aging effects for passive components.

All indications from inspections of the IP2 SGs in April 2006 were below calculated integrity limits in the pre-outage degradations assessment.

In April 2006, the regional inspection staff reviewed portions of the SG management plan, degradation assessment, and the final operational assessment to evaluate the SG inspection and management program. The staff reviewed plant-specific SG information, tube inspection criteria, integrity assessments, degradation modes, and tube plugging criteria. Entergy conducted eddy current testing of tubes in all SGs to detect and quantify tube degradation mechanisms and to confirm tube integrity following the completion of two fuel cycles of operation. The staff observed a sample of tubes from each generator to verify Entergy's examination of the entire length and made no significant findings. Confirmation of program compliance with established standards and regulations assures effective program management of passive component aging. The staff evaluated the SG tube inspection report for the

inspections performed during 2006, 2R17 refueling outage and concluded the applicant provided the information required by the technical specifications and that the applicant's inspection program appears to be consistent with the objective of detecting potential tube degradation and with industry operating experience at similarly designed units.

The staff confirmed that the "operating experience" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.34 and A.3.1.34, the applicant provided the UFSAR supplement for the Steam Generator Integrity Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.34 and A.3.1.34, the applicant has committed to enhance the program prior to entering the period of extended operation (Commitment 24).

Conclusion. On the basis of its review of the applicant's Steam Generator Integrity Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. Also, the staff reviewed the cited enhancement and confirmed that its implementation prior to the period of extended operation would make the existing AMP consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.15 Structures Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.36 describes the existing Structures Monitoring Program as consistent with GALL AMP XI.S6, "Structures Monitoring Program," with enhancements.

The applicant states that Structures Monitoring Program inspections are in accordance with 10 CFR 50.65 (Maintenance Rule) as addressed in Regulatory Guide 1.160 and NUMARC 93-01. Periodic inspections monitor the condition of structures and structural components for loss of intended function. As protective coatings are not relied upon to manage the effects of aging for structures in the Structures Monitoring Program, the program does not address protective coating monitoring and maintenance.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Structures Monitoring Program to verify consistency with GALL AMP XI.S6. Details of the staff's audit of this AMP are documented in the Audit Report. As documented in the report, the staff found that the Structures Monitoring Program elements "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria," are consistent with the corresponding elements in GALL AMP XI.S6.

Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

Enhancement 1. In the LRA, the applicant committed to implement the following enhancement to program element of "scope of program":

> Appropriate procedures will be revised to explicitly specify that the following structures are included in the program.
>
> - Appendix R emergency diesel generator foundation (IP3)
> - Appendix R emergency diesel generator fuel oil tank vault (IP3)
> - Appendix R emergency diesel generator switchgear and enclosure (IP3)
> - city water storage tank foundation
> - condensate storage tanks foundation (IP3)
> - containment access facility and annex (IP3)
> - discharge canal (IP2/3)
> - emergency lighting poles and foundations (IP2/3)
> - fire pumphouse (IP2)
> - fire protection pumphouse (IP3)
> - fire water storage tank foundation (IP2/3)
> - gas turbine 1 fuel storage tank foundation
> - maintenance and outage building–elevated passageway (IP2)
> - new station security building (IP2)
> - nuclear service building (IP1)
> - primary water storage tank foundation (IP3)
> - refueling water storage tank foundation (IP3)
> - security access and office building (IP3)
> - service water pipe chase (IP2/3)
> - service water valve pit (IP3)
> - superheater stack
> - transformer/switchyard support structures (IP2)
> - waste holdup tank pit (IP2/3)

From the applicant's description, the staff could not identify the complete scope of the program. Very significant enhancements to the "scope of program" are identified, but there is no description of the scope of the existing program, and there is no explanation why such major enhancements to the program scope are needed for license renewal. While most of the added structures serve a license renewal intended function for 10 CFR 54.4(a)(3), about half of these structures also serve license renewal intended functions for 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2). In accordance with RG 1.160 and NUMARC 93-01 these structures would be expected to be included in the current existing program.

In an audit question, the staff asked Entergy to (1) describe the structures and structural components inspected as part of the existing structures monitoring program; and (2) explain why 11 structures listed in the "scope of program" enhancement have intended functions for 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2) (Audit Item 85).

By letter dated December 18, 2007, the applicant responded to the audit item. In its response to (1), Entergy provided a list of the structures and structural components which are inspected as part of the existing Structures Monitoring Program. The staff reviewed this list and confirmed that it matched the list of existing structures presented in the program basis documents (PBDs).

In its response to (2), for each of the structures listed in the enhancement to the "scope of program" that have intended functions for 10 CFR 54.4(a)(1) or 10 CFR 54.4(a)(2), Entergy described its function and its specific intended function for license renewal. The staff reviewed this information and finds the response acceptable.

Enhancement 2. In the LRA, the applicant committed to implement the following enhancement to program element "scope of program":

> Appropriate procedures will be revised to clarify that in addition to structural steel and concrete, the following commodities are inspected for each structure as applicable.
>
> - cable trays and supports
> - concrete portion of reactor vessel supports
> - conduits and supports
> - cranes, rails, and girders
> - equipment pads and foundations
> - fire proofing (pyrocrete)
> - HVAC duct supports
> - jib cranes
> - manholes and duct banks
> - manways, hatches, and hatch covers
> - monorails
> - new fuel storage racks
> - sumps, sump screens, strainers and flow barriers

The staff notes that the specific commodities listed would be expected to be included in the current existing program if they are safety-related or important to safety. In an audit question, the staff asked Entergy to (1) describe the structural commodities inspected as part of the existing structures monitoring program; and (2) explain why the 13 commodities are identified as an enhancement to the "scope of program" (Audit Item 86).

By letter dated December 18, 2007, the applicant responded to the audit item. In its response to (1), Entergy explained that the structural commodities inspected as part of the existing program include structural steel beams, columns, and end connections; support steel (e.g., instrument racks, base plates); and concrete surfaces. Individual inspection checklists are provided in the program procedures for each commodity.

In its response to (2), Entergy explained that these 13 commodities are routinely inspected under the existing Structures Monitoring Program (AMP B.1.36); however, they are not explicitly identified in the program procedures. Therefore, this enhancement will be implemented to ensure that these commodities are explicitly identified in the program.

The staff concurs that all of the commodities identified in the enhancement need to be explicitly included in the Structures Monitoring Program (SMP). Anchorages (base plates, grout, and steel anchors) and connections (welds or bolts) to building steel, associated with all applicable supports should also be clearly identified. During follow-up audit discussions with Entergy, Entergy proposed to add the phrase "(including their anchorages)" to confirm that the support anchorages are included in the Structures Monitoring Program. The staff accepted Entergy's proposal. This additional enhancement to the "scope of program" element has been added to Commitment 25, in Revision 1 of the List of Regulatory Commitments, submitted by Entergy on December 18, 2007.

The staff also reviewed the LRA Structures AMR Tables 3.5.2-1 through -4 and noted that several structural components, which credit AMP B.1.36 for aging management, are not specifically identified in the existing program scope or in the enhancement. In an audit question, the staff requested Entergy to confirm that all component type/aging effect combinations that credit the Structures Monitoring Program for aging management in Tables 3.5.2-1 through 3.5.2-4 are included in the scope of the Structures Monitoring Program, and are inspected for the designated aging effect (Audit Item 244). In its response, dated December 18, 2007, Entergy stated that all component type/aging effect combinations that credit the Structures Monitoring Program for aging management in Tables 3.5.2-1 through 3.5.2-4 are inspected for designated aging effects; however, some structural components are not specifically identified in the scope of the Structures Monitoring Program. The staff finds this acceptable, because this AMP is applicable to aging management of the vast majority of structures and structural components in the plants.

Enhancement 3. In the LRA, the applicant committed to implement the following enhancement to program elements of "scope of program," and "detection of aging effects":

> Guidance will be added to the Structures Monitoring Program to inspect inaccessible concrete areas that are exposed by excavation for any reason. IPEC will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring.

The staff finds this enhancement acceptable, because it provides additional appropriate guidance for inspection.

Enhancement 4. In the LRA, the applicant committed to implement the following enhancement to program element "detection of aging effects": "[r]evise applicable structures monitoring procedures for inspection of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material."

The staff finds this enhancement acceptable, because it provides additional guidance for inspection.

Enhancement 5. In the LRA, the applicant committed to implement the following enhancement to program element "detection of aging effects":

> Guidance to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years) will be added to the Structures Monitoring Program. IPEC will obtain samples from a well that is representative of the ground water surrounding below-grade site structures. Samples will be monitored for sulfates, pH and chlorides.

The staff notes that Entergy's above enhancements to the Structures Monitoring Program are necessary for license renewal.

In an audit question, the staff requested Entergy to (Audit Item 87):

(a) describe past and present groundwater monitoring activities at the Indian Point site, including the sulfates, pH and chlorides readings obtained; and the location(s) where test samples were/are taken relative to the safety-related and important-to-safety embedded concrete foundations; and

(b) Explain the technical basis for concluding that testing a single well every five (5) years is sufficient to ensure that safety-related and important-to-safety embedded concrete foundations are not exposed to aggressive groundwater.

By letter dated December 18, 2007, the applicant responded to the audit item. In response to (a), Entergy stated:

> There is a sufficient number of analytical results to ensure that the ground water is being properly monitored. Large numbers of groundwater wells located adjacent to the structures have been sampled and were analyzed for sulfate and chloride at a contract laboratory, with pH having been determined at the time of sample collection. The data indicates that the ground water is non-aggressive (pH >5.5, Chloride <500 ppm and Sulfate <1500 ppm). Several samples taken along the facility waterfront and adjacent to the discharge canal were noted to have higher than normal levels of chloride. Given the location of samples, these higher than normal levels are believed to be due to the salinity of the brackish Hudson River water at the Indian Point location of the river. In all cases pH results are >5.5 and sulfate concentration < 1500 mg/L. Ground water samples will continue to be obtained on a quarterly basis for one calendar year in order to fully characterize these parameters (Chloride, Sulfate, and pH) for the groundwater at IPEC to account for any seasonal variation. The selected sample locations will provide representative samples of the ground water in the vicinity of the structures. A review of the several hundred ground water pH values collected in late 2005 to present reveal that the ground water had a pH of >5.5 in all cases except four. In those four cases, pH was found to be <5.5 standard unit (SU). All four of these low pH samples were obtained from the same sample point on the same day. To date all subsequent samples taken from this sample point were found to have a pH >5.5 SU.

In response to (b), Entergy stated: that at least five (5) wells will be tested. A sample frequency of five years in a limited number of wells (at least five wells) adjacent to safety structures and those falling under 10 CFR 54.4 (a)(1) and 10 CFR 54.4 (a)(2) would be sufficient to confirm the

non-aggressive nature of the ground water. The large sample population for the initial characterization, the diverse locations from which the samples were obtained and the seasonality of sample collections contribute to Entergy's confidence in the understanding of the nature of the ground water. Additionally, Entergy stated it would not normally expect to see the ground water conditions change unless an extraordinary event occurred, such as major withdrawals (such as significant pumping out the ground water) or injections of water on the site or in the vicinity of the site.

The staff finds Entergy's responses to be acceptable, on the basis that (1) extensive sampling has been recently conducted, without evidence of an aggressive below-grade environment; and (2) Entergy has committed to increase the sample size from one well to at least five wells in the vicinity of in-scope buried concrete structural elements. This new commitment was added to Commitment 25, in Revision 1 of the List of Regulatory Commitments, submitted by Entergy on December 18, 2007.

In LRA Appendix B, Table B-2, the applicant stated that GALL AMP XI.S7 is not credited for aging management of water control structures. Instead, the Structures Monitoring Program manages the effects of aging on the water control structures at IP. GALL AMP XI.S7 offers this option, provided all the attributes of GALL AMP XI.S7 are incorporated in the applicant's Structures Monitoring Program.

In an audit question, the staff requested Entergy to (1) identify the specific water control structures that have an intended function for license renewal, and are included in the scope of AMP B.1.36; (2) describe the attributes of AMP B.1.36 that pertain to aging management of water control structures; and (3) explain how these attributes of AMP B.1.36 encompass the attributes of GALL AMP XI.S7, without exception (Audit Item 88).

By letter dated December 18, 2007, the applicant responded to the audit item. In its response to (1), Entergy indicated that the water control structures that have an intended function for license renewal and are included (or will be included) in the scope of the AMP B.1.36 are the intake structure (including intake structure enclosure) and the discharge canal. Since the discharge canal is not specifically stated in the structures monitoring procedures, Entergy indicated that an enhancement for AMP B.1.36 will be to explicitly specify the discharge canal.

The staff concludes that the Structures Monitoring Program B.1.36 can be used to manage aging of the IP water-control structures, in lieu of GALL AMP XI.S7 (RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants).

In its response to (2), Entergy described the attributes of AMP B.1.36 that pertain to aging management of water-control structures. More detailed information was provided in Entergy's response to part (3) of the audit question.

In it response to (3), Entergy provided a description of how the ten attributes of AMP B.1.36 encompass the attributes of GALL AMP XI.S7. Compared to the five year intervals recommended for inspection in GALL AMP XI.S7, Entergy indicated the Structures Monitoring Program (AMP B.1.36) similarly uses intervals of five years for accessible areas and opportunistic inspections for buried components. The staff did not find this consistent with GALL AMP XI.S7 for submerged structures. During follow-up audit discussions with Entergy, Entergy proposed to revise LRA Commitment 25, to add the following: "Enhance the Structures

Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at lease once every 5 years, or earlier if determined to be necessary." The staff accepted Entergy's proposal, on the basis that it is consistent with GALL AMP XI.S7. This enhancement was added to Commitment 25, in Revision 1 of the List of Regulatory Commitments, submitted by Entergy on December 18, 2007.

Based on the staff's review of the LRA, the basis documents, Entergy's responses to the audit items discussed above, and Entergy's additions to Commitment 25, submitted on December 18, 2007, the staff concludes that the "scope of program," "parameters monitored or inspected," and the "detection of aging effects" program elements are consistent with the GALL Report. Also, consistent with the GALL report, the preventive actions program element is not applicable.

Operating Experience. LRA Section B.1.36 states that inspections of structural steel, concrete exposed to fluid, and structural elastomers from 2001 through 2005 revealed signs of degradation: cracks, gaps, and corrosion (rust). Monitoring of concrete structures and components from 2001 through 2006 identified only minor cracks that did not affect the structural integrity of the components. Monitoring of structural steel members revealed only minor corrosion. The applicant states that inspection intervals, adjusted as necessary, ensure that future inspections detect degradation prior to loss of intended function. The applicant also states that detection of degradation and corrective action prior to loss of intended function assure program effectiveness in managing aging effects for structural components.

The staff reviewed the discussion of operating experience for the existing plant-specific Structures Monitoring Program. In addition, the staff reviewed a number of condition Reports (CRs) that briefly describe occurrences of structural degradation at IP2 and IP3. Based on review of the CR summaries, the staff identified a number of apparently significant conditions of aging degradation of structures that are not identified in the LRA, the basis documents for the Structures AMPs, or the Structures AERM.

In a series of audit questions related to plant-specific operating experience for structures, the staff asked Entergy to provide additional information for the following types of degraded conditions:

Water Control Structures Degradation (Audit Item 358)
IP2 Reactor Cavity Leakage (Audit Item 359)
IP2 Spent Fuel Pool Crack/Leak Paths (Audit Item 360)
IP2 Containment Dome Concrete Spalling (Audit Item 361)

The staff referenced specific CRs that described each type of degradation, and asked Entergy to discuss:

(a) history of the degradation
(b) evaluation of the extent of degradation
(c) operability assessments performed
(d) corrective actions taken (describe in detail)
(e) the current status of the degraded condition
(f) corrective actions planned prior to the LR period

(g) special or augmented aging management requirements during the period of extended operation
(h) license renewal commitments

By letter dated, March 24, 2008, the applicant provided responses to the above questions. The staff evaluated Entergy's response for IP2 Containment Dome Concrete Spalling (Audit Item 361) in its assessment of Entergy's Containment ISI Program, LRA AMP B.1.8. See Section 3.0.3.3.2 of this SER.

Water Control Structures Degradation (Audit Item 358)

In its response for Water Control Structures Degradation, dated March 24, 2008, Entergy described the noted degraded conditions in greater detail, summarized corrective actions taken, and identified the current status of the degradation. For degraded areas that have not been repaired, Entergy will continue to monitor the degradation under the Structures Monitoring Program during the extended period of operation. However, Entergy initially made no commitment for augmented inspection during the extended period of operation for the degraded areas that have not been repaired. The staff informed Entergy that its responses to Items (g) and (h) needed additional clarification and also requested Entergy to provide the technical basis as to why augmented inspection during the extended period of operation is not necessary for the degraded areas.

The applicant provided its supplemental response in a letter dated August 14, 2008. In its response, the applicant stated that evaluations conducted under its corrective action program indicated the degraded conditions did not compromise intended functions at this time. The applicant committed to perform more frequent inspection of these locations (every three years instead of five years) under its Structures Monitoring AMP (Commitment 25).

The applicant has committed to more frequent inspection of the degraded water control structures, which is consistent with the GALL Report recommendation. The GALL Report references RG 1.160 for Maintenance Rule monitoring of structures. RG 1.160 recommends more frequent monitoring for areas of known degradation. The staff concludes that a 3 year monitoring frequency is sufficient to identify further degradation before there is loss of intended function. Therefore, the staff finds the applicant's response and supplemental clarification for Audit Question 358 to be acceptable.

IP2 Reactor Cavity Leakage (Audit Item 359)

In its response dated March 24, 2008, for IP2 Reactor Cavity Leakage, Entergy described the degraded conditions in greater detail, summarized corrective actions taken, and identified the current status of the degradation. The reactor cavity at IP2 has a history of leakage at the upper elevations of the stainless steel cavity liner when flooded during refueling outages. There is a relatively free flow of water behind the liner, down to the 46-foot elevation inside containment. Attempts have been made over the last several outages to mitigate this condition, with limited success. An action plan is being developed for a permanent fix to this issue. Two technologies are being investigated for the permanent solution.

For the extended period of operation, Entergy will rely on the Structures Monitoring Program for aging management of the reactor cavity concrete and containment internal structures. For aging management of the cavity steel liner, Entergy will rely on the Water Chemistry Control – Primary and Secondary Program. However, Entergy made no commitment for augmented inspection during the extended period of operation. The staff informed Entergy that its responses to Items (g) and (h) needed additional clarification. In a follow-up discussion relating to Audit Question 359, the staff expressed its concern with regard to the potential for degradation of the underlying concrete and reinforcement due to the leakage of borated water through the cavity liner and potential impact of the leakage on other adjacent structures. The staff requested Entergy to provide the technical basis as to why augmented inspection during the extended period of operation is not necessary, if the recurring leak condition is not permanently fixed.

The applicant provided its supplemental response in a letter dated August 14, 2008. In its response, the applicant stated that the leakage is entirely contained within and is collected in the lower elevation of the containment building. The cavity water leakage is easily replaced from the refueling water storage tank. The collected leakage is pumped to the radioactive liquid waste processing system and the leakage does not affect structures other than the refueling cavity. The applicant stated that the leakage does not pose a threat to the structural integrity of the refueling cavity reinforced concrete walls, which are 4 feet thick, and cited several documented tests that concluded borated water does not significantly degrade concrete properties. In addition, a core sample was removed from the IP2 refueling cavity wall in 1993. Examination showed that the depth of penetration of borated water was ½ inch into the concrete at that time. The applicant stated that substantial design margins are available in the concrete and reinforcement. The applicant emphasized that the flooded condition, and therefore the leakage exists for about 2 weeks out of a refueling cycle of about 1.5 years. A number of attempts have been made to rectify this condition, but to date have not been completely successful. The applicant indicated that it will continue to work toward a permanent fix, but will prioritize this effort based on its safety significance and availability of site resources. The applicant has committed to perform a one-time inspection and evaluation of a sample of potentially affected refueling cavity concrete, including embedded reinforcing steel, prior to the period of extended operation, in order to provide additional assurance that the concrete walls have not degraded (Commitment 36).

As noted at the beginning of this program section, the applicant claims that it is consistent with the GALL Report AMP XI.S6 with enhancements. The GALL Report AMP recommends that for each structure/aging effect combination, the specific parameters monitored or inspected should be selected to ensure that aging degradation leading to loss of intended functions will be detected and the extent of degradation can be determined. For the program element "detection of aging effects," the AMP recommends that for each structure/aging effect combination, the inspection methods, inspection schedule, and inspector qualifications should be selected to ensure that aging degradation will be detected and quantified before there is loss of intended functions. The staff notes that the applicant plans to enhance the "detection of aging effects" element of its Structures Monitoring Program to inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. However, the leakage is occurring in inaccessible areas, and a similar environment may not exist for accessible areas of concrete.

The staff concluded that Entergy's commitment to perform a one-time inspection and evaluation of a sample of potentially affected refueling cavity concrete, including embedded reinforcing steel, prior to the period of extended operation, is appropriate in order to assess the current state of the concrete and rebar. However, because the applicant does not plan to perform periodic inspections of the refueling cavity and affected area, the staff determined that for this structure/environment/aging effect combination, the applicant is not consistent with the GALL Report AMP. Additionally, the applicant's program did not address concrete exposed to borated water.

In a telephone call with Entergy on August 27, 2008 (Audit Item 359), the applicant described its plan for permanent remediation of the IP2 refueling cavity leakage problem. By letter dated November 6, 2008, the applicant submitted a supplemental response to Audit Question 359, describing its plan for implementing a permanent fix over the next three (3) scheduled IP2 refueling outages (2010, 2012, 2014).. At the time of issuance of the SER with Open Items, the staff was in the process of reviewing the applicant's response. Therefore, this issue was identified as Open Item 3.0.3.2.15-1.

Entergy's proposed plan to mitigate the refueling cavity leak includes:

- 2008 / 2009 - Research available technologies to repair leaks in the refueling cavity.
- Spring 2010 refueling outage - Repair area of north wall weld seams in the vicinity of the Ceramoloy patch and south wall along area of disbonded Ceramoloy patch.
- Spring 2012 refueling outage - Repair east wall where large Ceramoloy patch has disbonded and area around access ladder on northwest corner.
- Spring 2014 refueling outage - Repair areas of lower cavity where Ceramoloy patches have disbonded, and miscellaneous areas observed as suspect from past inspections.
- During each of the preceding outages, areas not permanently repaired will be temporarily repaired by the application of Instacote. Beginning in the refueling outage in Spring 2016, no Instacote will be applied, to allow Entergy to determine if repairs have successfully stopped the leakage. If not, additional areas will be repaired in subsequent outages until the leakage is corrected.

The staff reviewed the applicant's response dated November 6, 2008, and noted that the applicant did not make a license renewal commitment to permanently remediate the refueling cavity leakage. Therefore, the staff determined that the applicant should define an appropriate aging management program to be implemented if the remediation plan is not completely successful in stopping the leakage.

In an effort to resolve this open item, the staff issued follow-up RAI 1: Open Item 3.0.3.2.15-1 (Audit Question 359), dated April 3, 2009, in which the staff requested the following information:

(a) . . . provide additional information on the leakage path from the refueling cavity to the collection point lower in containment, as well as the leak flow-rate. In this regard, describe the leakage path and chemical composition of the leaking fluid, provide historical flow-rate values, and

confirm whether or not any leakage enters the reactor cavity inside the primary shield wall. Provide the technical basis as to how the leakage path was determined, with a focus on water entering the reactor cavity. Provide a sketch of containment and the refueling cavity which highlights the leakage path.

(b) . . . In absence of a formal commitment to remedy the source of leakage, the applicant's aging management program (AMP) should include a method to monitor for a degrading condition in the refueling cavity, and other structures and components that would be affected by the leakage, during the period of extended operation, or the applicant should explain how the structures monitoring program will adequately manage potential aging of this region during the period of extended operation.

In letter dated May 1, 2009, Entergy responded to follow-up RAI 1: Open Item 3.0.3.2.15-1 (Audit Question 359), stating as follows:

(a) During the first refueling outage in 1976, leakage from the refueling cavity was observed coming from the reactor cavity. The original designed temporary seal between the reactor vessel flange and the reactor cavity was not leak tight. The leakage collected in the reactor cavity pit sump and was pumped out. A plant modification was initiated to use a new design seal, which resolved the problem. Leakage also occurred in the reactor vessel inlet and outlet blow out plugs and instrumentation wireways. Leakage through these paths has been minimized by improving sealing methods. The leakages from the above sources were not from behind the reactor cavity liner and through concrete construction joints.

In 1993, it was determined that leakage from the refueling cavity was coming through the liner plates. This event initiated detailed investigations and corrective actions to stop the leakage. Unfortunately, the sealing methods have not fully resolved the leakage. The suspect leakage path was determined by visual observation during and after filling the refueling cavity with water. Leakage is observed as the cavity is filled for refueling operations. Leakage starts as the cavity level reaches the 80 ft. elevation which is approximately 50% cavity level. Leakage was observed initially from three significant areas associated with refueling cavity construction. [Applicant referenced Figure 1, included with the response.] Leakage from the refueling cavity collects in a drainage trench on the 46 ft elevation of containment inside the crane wall from where it flows to the containment sump.

A small portion of the leakage from the refueling cavity enters the reactor cavity flowing down the interior primary shield walls to a sump located in the reactor cavity from where it is pumped to the containment sump. Leakage inside the reactor cavity has been primarily attributed to non-liner leakage associated with reactor cavity seal and nozzle inspection box cover isolation issues.

The leaking fluid from the refueling cavity is mixed reactor coolant and refueling water storage tank water with total estimated flow rates on the order of 3 to 7 gpm. No samples of the fluid flowing from the leaking areas have been analyzed for chemical composition. There has been no degradation of containment structural surfaces from this wetting as observed in the Structures Monitoring Program. [Applicant referenced Figures 1 through 4, included with the response, for sketches of the containment area and the refueling cavity which show the locations of the observed leakage.]

(b) As previously described in IPEC Letter NL-08-127 dated August 14, 2008, Audit Question 359, the refueling cavity is a robust structure, with thick walls and low stress levels when compared to the total structural capacity. Exposure to borated water has not resulted in identified degradation or reduction of structural integrity. Industry and IPEC operating experience for the past years has shown that concrete is not significantly affected by exposure to borated water. The refueling cavity is wet during the limited duration (approximately 14 days) when it is filled and is dry during the subsequent period (approximately 24 months) of normal power operations. Moisture remaining following draining of the cavity would be dried up by the ambient temperatures resulting from reactor operation, thus long-term exposure to borated water that could cause significant degradation of the concrete and embedded reinforcement is not expected.

The method to monitor for a degrading condition in the refueling cavity is routine visual inspection of accessible concrete surfaces under the Structures Monitoring Program accompanied by an inspection of concrete that has been exposed to the intermittent borated water leakage for an extended period. The inspection is required by the formal commitment to do core bore samples in the upcoming outage in 2010 for concrete that has been exposed to the leaking borated water on an intermittent basis for much of the life of the plant. If leakage occurs during the upcoming outage, IPEC will obtain a sample of leaking water at an exit point below the cavity and evaluate it for fluid composition.

The results of the sample analysis will be evaluated to establish whether additional aging management activity is necessary during the period of extended operation. Additionally core bore samples will be taken, if leakage is not stopped prior to the end of the first ten years of the period of extended operation (Reference Commitment #36). Other structures and components that could be affected by the leakage that are not addressed under the Structures Monitoring Program would be evaluated under the Boric Acid Corrosion Program. As previously committed to in IPEC Letter NL-08-127, dated August 14, 2008, inspections and activities related to the identification of leakage in the refueling cavity and its impact on the surrounding concrete will provide reasonable assurance that the associated structures will remain capable of fulfilling their license

renewal intended functions. The established site operating experience review program ensures that any subsequent new industry or IPEC operating-experience will be incorporated to ensure adequate management of potential aging effects of this region during the period of extended operation.

The staff reviewed the applicant's May 1, 2009 response and concluded that additional clarifications were needed before the staff could make a determination whether the applicant's revised commitments are sufficient to ensure there will be no loss of intended function during the 20 year extended period of operation.

In an effort to resolve this issue, the staff issued follow-up RAI 2: Open Item 3.0.3.2.15-1, dated May 20, 2009, which requested the following:

(a) In part (a) of the applicant's response, Figures 1 through 4 do not clearly identify the flow path from the refueling cavity liner to the A, B, and C water exit locations. . . . In an elevation view (similar to Figure 2), cut through each of the exit locations A, B, and C, showing the horizontal and vertical dimension between the entry point through the liner and the exit location. To the extent possible, describe the possible circumferential traverse of the leakage, from the entry point through the liner to the exit location.

(b) The staff requests the applicant to provide the following additional information/clarification regarding the revised license renewal commitments in part (b) of the applicant's response:

(1) The current remediation plan has targeted the 2014 outage for completion. Please identify actions that will be taken if the remediation plan is unsuccessful.

(2) Identify the specific location and number of the concrete core samples (e.g., the three water exit locations) that will be removed and tested (i) during the upcoming 2010 refueling outage, and (ii) at 10 years into the extended period of operation (if a permanent solution for the leakage has not been achieved, in accordance with Entergy's current remediation plan). Define the tests that will be performed, and the objective of each test.

(3) Please advise if the revised commitments in the applicant's May 1, 2009 response include chemical analysis of the leaking water (i) during the upcoming 2010 refueling outage, and (ii) at 10 years into the extended period of operation. Please identify the analyses that will be performed, and the objective of each analysis.

In its response, dated June 12, 2009, Entergy responded to follow-up RAI 2: Open Item 3.0.3.2.15-1 as follows:

a. Based on leakage investigations, the reactor refueling cavity begins to leak when the water in the cavity reaches an approximate elevation between 80'- 85'. As can be seen on the attached elevation views of the cavity (Entergy provided Figures 1 thru 4 in its response), horizontal weld seams exist between these elevations, but the exact liner leakage points are unknown. We can, however, make the following observations regarding the relationship between the leakage areas in the concrete structure denoted as points A, B and C, and conditions of the cavity liner:

   1. Above point A, defects in the CeramAlloy patch along a horizontal weld seam located on the south wall at an elevation between 80'-85' has been observed. The CeramAlloy patch material that covers several weld seams was a previous attempt to mitigate the cavity leakage. This is a potential cavity liner leak point for the observed leakage on the concrete structure at point A.

   2. Above the exit point denoted as B, defects in a CeramAlloy patch along a horizontal weld seam located at an elevation between 80'– 85' on the south wall has been observed. This patch area is an extension from the area discussed in Item 1 above. In addition, the upper internals stand support base is attached to the cavity floor above the vicinity of the observed leakage in the concrete structure at point B. Both these areas in the cavity liner are potential leak point sources for the observed leakage at point B.

   3. Above the observed leakage area in the concrete structure denoted as point C, defects in both the CeramAlloy patches along weld seams and potential defects in the weld seams themselves at the north cavity wall have been observed. These defects are located approximately 10-15' above the cavity floor and are potential leak points for the leakage observed at point C.

b. The following provides Entergy's response to part (b) of the staff's request.

   1. Should the remediation plan for the cavity liner targeted for completion during the 2014 outage be unsuccessful, Entergy will perform additional monitoring to assess the condition of potentially affected structures. To assure continued structural integrity of the reactor refueling cavity reinforced concrete walls, Entergy will perform further core sampling and inspect reinforcing steel at suspect locations as described in Item 3.

   2. (i) During the upcoming 2010 outage, a total of 3 core bore samples will be taken from the reinforced concrete walls that form the outer shell of the reactor refueling cavity steel liner. The

locations of these core bores will be chosen based on the following:

- Locations in the vicinity of observed liner/liner patch degradation in relative proximity to the observed leak points A, B and C on the concrete structure.

- Accessibility of suspect areas based on the principle of As Low As Reasonably Achievable (ALARA) and physical interferences.

The core samples will be tested and chemically analyzed to determine the effect, if any, past leakage has had on the concrete properties. The objectives of the physical and chemical tests of the concrete core samples are as follows:

- Determine the compressive strength of concrete.
- Determine boron and chloride concentration in concrete.
- Determine pH of concrete.

In addition, a petrographic examination will be performed on the core samples to evaluate the cementitious matrix, and, to the extent possible, determine the durability of the concrete.

In addition, reinforcing steel in the core sample areas will be exposed and inspected. Visual inspections of the reinforcing steel will be performed to determine the extent of material loss, if any, from the steel as a result of the borated water leakage.

(ii) If a solution to the leakage has not been achieved, Entergy will perform core samples and reinforcing steel inspections prior to 10 years into the period of extended operation. Locations of the core samples will be chosen based on the extent and location of the leakage remaining following previous repair efforts. Core samples will be tested and chemically analyzed as discussed under part 2 above. Visual inspections of the reinforcing steel will be performed to determine the extent of material loss, if any, from the steel as a result of the borated water leakage.

3. (i and ii) Revised Commitment 36 includes chemical analysis of water leakage from the refueling cavity. During the upcoming 2010 outage, Entergy will collect water samples from the cavity leak and perform chemical analysis. If the leakage has not been stopped, Entergy will collect additional water samples of the leak during the same outage as the core samples are taken, no later

than 10 years into the period of extended operation. The water that is collected will be analyzed for the following:

- Boron concentration
- pH
- Iron
- Calcium

Results of the analysis will be evaluated to assess the aggressiveness of the leaking fluid to reinforced concrete structures.

The staff reviewed the applicant's responses to the staff's RAIs and clarification concerning the IP2 refueling cavity leakage (Audit Item 359) provided in letters dated March 24, 2008, August 27, 2008, November 6, 2008, May 1, 2009, May 20, 2009, and June 12, 2009. The staff noted the following:

- The borated water leakage during the reactor refueling operations has not adversely affected the structural integrity of the refueling cavity concrete structure. The leakage occurs for a short duration (approximately 14 days) during refueling outages (normally every 24 months). Visual examination of the leakage areas has not identified any degradation of concrete. In addition, previous studies and testing by the nuclear industry and the applicant have not identified any degradation of the concrete or reinforcement when exposed to low concentrations of borated water.

- The applicant has committed to take three core bore samples of the concrete, at the observed leakage locations, during the upcoming 2010 outage. The samples will determine the compressive strength and the pH value of concrete, as well as the boron and chloride concentration in the concrete. This information will be used to determine the effect of borated water on the concrete. Petrographic examination of the core samples will also help identify the effect of borated water on the durability of the IP2 refueling cavity area concrete prior to the period of extended operation.

- Visual examination of reinforcement exposed during core boring of concrete during the 2010 outage will identify any material loss due to corrosion resulting from interaction with borated water.

- The applicant has committed to analyze the water leaking from the refueling cavity for boron concentration, pH, iron, and calcium during the 2010 outage. This analysis will provide additional information on the effect of the leakage on the reinforced concrete structures.

- The applicant's goal is to permanently remediate the refueling cavity leakage by the end of the 2014 refueling outage. Since the leakage is the source of possible degradation, eliminating the leakage will also eliminate the possible degradation mechanism. However, if the remediation is unsuccessful, the applicant has committed to re-inspect the concrete, rebar, and leaking water prior to the tenth year of extended operation. The staff finds the timing of this inspection acceptable based on site-specific operating experience. IP2 has experienced refueling cavity leakage since 1993, which means the

concrete has been exposed to the leakage during refueling outages for at least 16 years with no visible signs of degradation. If the 2010 inspections also show no degradation after 16 plus years of intermittent leakage, there is reasonable assurance that a follow-up inspection within 10 years will detect any future degradation prior to a loss of intended function of the refueling cavity structures.

Based on the inspections conducted to date and the actions the applicant is planning to take prior to and during the period of extended operation, the staff finds that the aging effects on the IP2 refueling cavity concrete will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3). Therefore, Open Item 3.0.3.2.15-1 is closed.

IP2 Spent Fuel Pool Crack/Leak Paths (Audit Item 360)

In its response for IP2 spent fuel pool (SFP) crack/leak paths, Entergy described the noted degraded conditions in greater detail, summarized corrective actions taken, and identified the current status of the degradation. The leakage was first discovered during excavation for the IP2 Fuel Storage Building in 2005. Entergy believes the conditions leading to leakage have been corrected.

For the extended period of operation, Entergy will rely on the Structures Monitoring Program for aging management of the spent fuel pool concrete, and rely on the Water Chemistry Control – Primary and Secondary Program and monitoring of the pool level per technical specifications for aging management of the spent fuel pool stainless steel liner. However, Entergy made no commitment for augmented inspection during the extended period of operation. The staff informed Entergy that its responses to Items (g) and (h) needed additional clarification. Due to the lack of a leak-chase channel system at IP2 to monitor, detect and quantify potential leakage through the SFP liner, the staff is concerned that there has been insufficient time following the corrective actions to be certain that the leakage problems have been permanently corrected. In a follow-up discussion with regard to Audit Question 360, the staff requested Entergy to provide the technical basis as to why augmented inspection during the extended period of operation is not necessary.

The applicant provided its detailed response in a letter dated August 14, 2008. In its response, the applicant stated that all known sources of leakage from the IP2 spent fuel pool have been eliminated based on the inspections and repairs already implemented. The licensee stated that it completed, in 2007, a one-time inspection of the accessible 40 percent of the SFP liner above the fuel racks and 100 percent of the SFP transfer canal liner using general visual, robotic cameras and vacuum box testing techniques. To provide additional indication of potential spent fuel pool leakage, the applicant has committed to test the groundwater outside the IP2 spent fuel pool for the presence of tritium from samples taken from adjacent monitoring wells, every 3 months. The presence of tritium in the groundwater could be indicative of a continuing leak from the spent fuel pool (Commitment 25). The applicant has also revised the LRA description of its Structures Monitoring AMP to include this special testing as an enhancement.

Although Entergy has taken corrective action and has committed to quarterly monitoring for tritium in the groundwater, the staff was concerned that hidden degradation of concrete and rebar may have resulted from prior leakage, and may be continuing if there is still an active leakage mechanism. In a telephone call with Entergy on September 3, 2008, the staff requested the applicant to submit additional relevant information on the condition of concrete

and rebar in areas where leakage was detected, and the existing design margins in these areas.

By letter dated November 6, 2008, the applicant submitted a supplemental response to Audit Item 360, which provided a detailed description of (1) the design margins for the spent fuel pool concrete walls; and (2) the results of prior concrete core sample testing and rebar corrosion testing. At the time of issuance of the SER with Open Items, the staff was in the process of reviewing the applicant's response. Therefore, this issue was identified as Open Item 3.0.3.2.15-2. The applicant's letter of November 6, 2008, provided the following information:

> IPEC analyzed the capability of the east spent fuel pool pit wall and the south spent fuel pool pit wall to resist the design basis loads considering potential concrete and reinforcement steel degradation due to observed leakage of fluids through these walls. Finite Element models for both the east and south walls were developed to determine the actual forces in the walls due to loading resulting from the design basis earthquake, hydrostatic forces and dead weight. Due to the symmetry of the spent fuel pit structure, results from the evaluation of these two walls are applicable to the remaining north and west walls. The following summarizes the results and conclusions from these two analyses.
>
> East Wall Evaluation
>
> The capacity of the east wall was evaluated in response to possible degradation due to an observed leak in 1992. It was determined that work in the spent fuel pool in 1990 initiated the leak by inadvertently creating a small hole in the stainless steel liner. This condition was repaired in 1992. A total of 20 core bores were taken from 5 locations on the east wall in the vicinity of the observed leakage to determine the condition of the concrete following exposure to borated water leakage. At each of the 5 locations, 4 individual cores 4" in diameter and 15" in length were taken, resulting in a total depth of penetration into the wall of 60". In addition, several windows in the outer surface of the wall were created to allow inspection of the outer layer of reinforcing steel. Of the 20 cores taken, all but one had compressive strengths that exceeded the design strength of 3000 psi. This one core outlier had a measured compressive strength of 2400 psi.
>
> The lower value was attributed to its close proximity to a known concrete sub-surface delamination in the wall and was not considered to be representative of the general condition of the wall. Analysis of the concrete matrix showed that the borated water had little or no effect on the concrete itself. Little or no corrosion was observed in the rebar except at a location in the wall where spalling had occurred exposing rebar to the elements. Analysis of the rust particles showed high chloride content and low boron concentration indicating that rainwater was the primary cause of the observed corrosion. To determine the available margin in the east wall, moments were calculated using a finite element plate model. The results of the analysis showed the east wall was capable of resisting the applicable forces without any reinforcing steel and would incur little or no cracking as a result of the design loading. Conservatively assuming that the

concrete would crack and the bending moments would be carried by the reinforcing steel, the following minimum margins exist with respect to the ultimate moment capacity of the wall. In other words, the load bearing capability of the wall is at least 31% greater than the required load bearing capability.

Northeast Corner 1/ 4to 1/2 wall depth: 31%
Mid Span 1/ 4to 1/2 wall depth: 43%

South Wall Evaluation

An evaluation determined the margins in the south wall due to possible rebar degradation as a result of observed fluid emanating from a crack discovered in the west corner during excavation for the dry cask storage project. The reinforcing steel in the area of the observed leak was exposed for inspection. The condition of the reinforcing steel was good with little or no corrosion. To determine the actual forces in the south wall due to the design basis loads, a finite element model of the wall was developed. Based on the resulting moments from the analysis, the margins in the south wall with respect to the ultimate moment capacity of the concrete section are as noted below:

Section with Horizontal Steel at Wall Center: 45%
Section with Horizontal Steel at Crack Location: 51%
Section with Vertical Steel at Crack Location: 57%
Section with Vertical Steel at Base: 25%

The available margins in the east and south walls of the spent fuel pool pit with respect to the as-designed condition range from a low of 25% at the base of the wall for the vertical steel to a high of 57% for the vertical steel at the crack location in the west corner of the wall. The margins for the horizontal rebar at wall mid span range from 43%-45% and up to 51% in the vicinity of the observed crack.

The staff reviewed the applicant's November 6, 2008 response, and determined that additional clarifications were necessary before it could conclude that the applicant's proposed aging management program for the extended period of operation is sufficient.

In an effort to resolve this open item, the staff issued follow-up RAI 2: Open Item 3.0.3.2.15-2 (Audit Question 360), dated April 3, 2009, which requested the following:

(a) In Commitment 25, the applicant commits to sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least every three months to assess for potential indications of spent fuel pool leakage. This commitment does not describe what actions will be taken if leakage continues. If sampling indicates continued leakage, the applicant's AMP should include a method to determine if a degraded condition exists during the period of extended operation, or the applicant should explain how the Structures Monitoring Program will adequately manage potential aging of the inaccessible concrete of the IP2 spent fuel

pool due to borated water leakage during the period of extended operation.

(b) The second paragraph on page 2 of Attachment 1 of the clarification letter dated November 6, 2008, states in part: "[l]ittle or no corrosion was observed in the rebar except at a location in the wall where spalling had occurred exposing rebar to the elements. Analysis of the rust particles showed high chloride content and low boron concentration indicating that rainwater was the primary cause of the observed corrosion." The staff requests the applicant to identify any Unit 2 and Unit 3 operating experience related to rebar corrosion, in light of the chloride content in rainwater, and identify the likely source for the high chloride content in the rainwater. Additionally, the applicant is requested to explain whether and how the AMP is adequate to address this environment and the related potential aging effects to ensure there is no loss of intended function during the period of extended operation.

By letter dated May 1, 2009, Entergy provided the following response to follow-up RAI 2: Open Item 3.0.3.2.15-2 (Audit Question 360):

(a) As indicated in Entergy letter NL-08-127, dated August 14, 2008, Audit Question 360, degradation has not been attributed to the effects of aging, but to poor construction and workmanship practices during initial construction activities. Consequently, future degraded conditions are not expected.

The method to determine if a degraded condition exists during the period of extended operation is continued monitoring for leakage by monitoring SFP level and monitoring ground water in the vicinity of the pool exterior walls for indications of pool leakage. The absence of leakage will indicate no degraded condition exists. Leakage, if any, indicates potential degradation. If leakage is found, it will be evaluated under the corrective action program (i.e., Element 7 of the SMP). If sampling indicates that ground water contains constituents indicating pool leakage then evaluation is required under the corrective action program to assess the potential for degradation and determine appropriate corrective actions. An example of the aggressive corrective actions expected in response to identified leakage is found in the condition report described in response to Audit Question 360, Entergy Letter NL-08-127, dated August 14, 2008. Corrective actions for that condition included inspections of all accessible surfaces of the SFP liner, installation of monitoring wells in the vicinity, performance of UT examinations, bore samples, rebar inspections and inspections using remote camera technology.

As stated in the Statement of Consideration (SOC) for the license renewal rule, 'Given the Commission's ongoing obligation to oversee the safety and security of operating reactors, issues that are relevant to current plant operation will be addressed by the existing regulatory process within the present license term rather than deferred until the time

of license renewal.' Since the issue of SFP leakage is currently being addressed by the existing licensing and regulatory process that process provides reasonable assurance that appropriate corrective actions will be taken during the current license term. Those actions will continue as appropriate through the period of extended operation.

(b) The original 1993 consultant analysis associated with the degraded concrete area speculated that the likely source for the high chloride content was condensation of chloride laden air (chlorides from the brackish Hudson River water) on the outer surface of the pool wall. It has since been concluded that the chloride source was likely associated with the use of rock salt or storage of chemicals or materials in the area.

Studies of the chloride content in rain water and ground water do not support the levels that were found in 1993. Studies typically show the national average of chlorides in rain water to be a maximum of 1.0 to 1.5 parts per million (PPM) with values inland approaching 0.2 PPM. The National Atmospheric Deposition Program (NAPD), Hudson Valley location West Point station, located upriver from the plant, chloride data from 1983 to 2007 shows values from 0.18 to 0.66 PPM. This is significantly lower than the values initially reported and does not support the supposition that chlorides originated from rainwater. No IP operating experience has linked high chlorides in rainwater to corrosion of embedded rebar. The pool wall was repaired eliminating the spent fuel pool rebar exposure to rainwater.

The aging management programs for concrete exposed to the elements, the Structures Monitoring Program and the Containment ISI Program, are adequate to address this environment and the related potential aging effects to ensure there is no loss of intended function during the period of extended operation. Visual inspections performed under these programs have confirmed no loss of intended function due to aging effects. These programs will continue to monitor potential future degradation of the concrete cover that could result in exposure of the underlying rebar to the outdoor environment.

Minor degradation that has been observed during these inspections has shown little change between inspections confirming the adequacy of the inspection frequency of the Structures Monitoring and Containment ISI Programs. If rebar degradation is identified during future inspections (e.g., observation of concrete staining during visual inspection), the condition will be evaluated in accordance with the program requirements to ensure necessary corrective actions are taken to prevent loss- of intended function.

The staff reviewed the applicant's response dated May 1, 2009 and the applicant's previous responses concerning spent fuel pool leakage. The staff noted the following:

- A leak in the East wall of the spent pool liner was originally observed and repaired in 1992. This leak was traced to work performed in the spent fuel pool during 1990. The applicant took 20 core bore samples of the concrete from the affected wall and tested them. In addition, the condition of the reinforcement in the core bored areas was visually examined. Detailed structural analysis of the spent fuel pool structure was performed that concluded that the condition of the spent fuel pool walls was adequate to resist the postulated design loads.

- Spent fuel pool leakage was again observed in 2005. The applicant performed extensive testing of the spent pool liner using visual, robotic camera, and vacuum box testing techniques in 2007 and eliminated all known sources of spent fuel pool leakage.

- Currently there is no evidence of continued leakage from the IP2 spent fuel pool.

- The applicant has committed to sample for tritium in the groundwater wells in close proximity to the IP2 spent fuel pool every three months (Commitment 25). Tritium in the groundwater would indicate leakage from the spent fuel pool, which may lead to degradation. Any identified leakage will be reviewed and the corrective action program will be used to determine the appropriate actions.

Based on inspections conducted under the applicant's Structures Monitoring Program, and the applicant's additional commitment to monitor the groundwater samples from monitoring wells adjacent to the spent fuel pool, there is reasonable assurance that any degradation of the IP2 spent fuel pool would be identified, and evaluated within the corrective action program prior to loss of intended function. Therefore, the staff concludes that the effects of aging will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). On this basis, Open Item 3.0.3.2.15-2 is closed.

UFSAR Supplement. In LRA Sections A.2.1.35 and A.3.1.35, the applicant provided the UFSAR supplement for the Structures Monitoring Program. By letter dated March 24, 2008, the applicant revised LRA Sections A.2.1.35 and A.3.1.35 and Commitment 25 to: (1) include inspection of anchorages of certain commodities; (2) inspect inaccessible concrete areas that are exposed by excavation for any reason, and inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant degradation is occurring; (3) perform inspections of elastomers to identify cracking and change in material properties, and inspections of aluminum vents and louvers to identify loss of material; (4) obtain samples from at least five monitoring wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results; (5) inspect normally submerged concrete portions of the intake structures at least once every 5 years, and inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years; and (6) inspect the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the period of extended operation. By letter dated June 12, 2009, the applicant revised Commitment 36, which complements the Structures Monitoring Program, as discussed above. The staff reviewed these sections, as revised, and determines

that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

As documented in LRA Sections A.2.1.35 and A.3.1.35, the applicant has committed to enhance the program prior to entering the period of extended operation (Commitment 25).

Conclusion. On the basis of its audit and review of the applicant's Structures Monitoring Program, and review of the applicant's responses to the staff's RAIs, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent therewith. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.16 Water Chemistry Control - Closed Cooling Water Program

Summary of Technical Information in the Application. LRA Section B.1.40 describes the existing Water Chemistry Control - Closed Cooling Water Program as consistent with GALL AMP XI.M21, "Closed-Cycle Cooling Water System," with exceptions and enhancements.

The Water Chemistry Control - Closed Cooling Water Program includes preventive measures that manage loss of material, cracking, or fouling for components in closed cooling water systems: CCW, instrument air closed cooling, EDG cooling, SBO/Appendix R diesel generator cooling (IP2), Appendix R diesel generator cooling (IP3), security generator cooling, conventional closed cooling (IP2 only), and turbine hall closed cooling (IP3 only). These chemistry activities monitor and control closed cooling water chemistry using IP procedures and processes based on EPRI guidelines for closed cooling water issued as EPRI TR-1007820, "Closed Cycle Cooling Water Chemistry," Revision 1, dated April 2004, superseding EPRI TR-107396, "Closed Cycle Cooling Water Chemistry Guideline," Revision 0, issued November 1997, and a reference in the GALL Report. A description of differences between Revision 0 and Revision 1 follows.

The purpose of Revision 0 was to assist plants in developing water treatment strategies to protect carbon-steel and copper-containing systems from corrosion. This revision provides not precise, but broad direction for plants to develop closed cooling water chemistry control programs by utilizing the report to tailor specific station programs. Revision 0 does not provide tables for "control parameters" and "diagnostic parameters" with respective sampling frequency and expected values. However, it shows parameters that should be monitored as "control parameters" or "diagnostic parameters." In general, Revision 0 allows plants a great deal of flexibility in developing their closed cooling water chemistry programs.

Revision 1 is significantly more directive and incorporates action levels with established thresholds for specific actions required. This revision specifically establishes recommended monitoring frequencies and clearly specifies expected parameter values. Revision 0 treats total organic carbon, dissolved oxygen, total alkalinity, calcium/magnesium, and refrigerants as

diagnostic but these are not described in Revision 1 which considers none of these parameters (or monitoring of them) as having any effect on the long-term condition of closed cycle cooling water systems.

Both EPRI closed cycle cooling water guidelines distinguish clearly between "control parameters" and "diagnostic parameters." Adherence to control parameters is expected whereas diagnostic parameters are suggested but can be plant-specific. Deviations from EPRI recommended diagnostic parameters are not exceptions to the GALL Report.

Future revisions of the EPRI closed cycle cooling water guidelines will be adopted as required commensurate with industry standards. The One-Time Inspection Program for Water Chemistry utilizes inspections or NDEs of representative samples to verify whether the Water Chemistry Control - Closed Cooling Water Program has been effective in managing aging effects.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Water Chemistry Control - Closed Cooling Water Program to verify consistency with GALL AMP XI.M21. Details of the staff's audit of this AMP are documented in the Audit Report. As documented in the report, the staff found that the Water Chemistry Control - Closed Cooling Water Program element "scope of program" is consistent with the corresponding element in GALL AMP XI.M21. Because this element is consistent with the GALL Report element, the staff finds that it is acceptable.

The staff reviewed the exceptions and enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited.

Exception 1. In the LRA, the applicant took the following exception to the GALL Report program element "parameters monitored or inspected": "NUREG-1801 states the program monitors the effects of corrosion and SCC by testing and inspection in accordance with guidance in EPRI TR-107396. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform performance and functional testing."

The staff noted that the discussion of this exception in Section B.1.40 of the LRA includes a footnote, which states the following:

> While NUREG-1801, Section XI.M21, Closed Cycle Cooling Water System endorses EPRI report TR-107396 for performance and functional testing guidance, EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive CCW system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be included as part of maintenance rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection

Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

Exception 2. In the LRA, the applicant took the following exception to the GALL Report program element "detection of aging effects": "NUREG-1801 recommends the use of performance and functional testing to ensure acceptable function of the CCCW systems. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform performance and functional testing."

The staff noted that the discussion of this exception in Section B.1.40 of the LRA includes a footnote, which states the following:

> While NUREG-1801, Section XI.M21, Closed Cycle Cooling Water System endorses EPRI report TR-107396 for performance and functional testing guidance, EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive CCW system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be included as part of maintenance rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

Exception 3. In the LRA, and in Amendment 1 to the LRA, Attachment 1, Audit Item 95, dated December 18, 2007, the applicant took the following exception to the GALL Report program element "monitoring and trending": "NUREG-1801 recommends internal visual inspections and performance and functional tests periodically to demonstrate system operability. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform component performance and functional testing."

The staff noted that the discussion of this exception in Section B.1.40 of the LRA includes a footnote, which states the following:

> While NUREG-1801, Section XI.M21, Closed Cycle Cooling Water System endorses EPRI report TR-107396 for performance and functional testing guidance, EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive CCW system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can

be accomplished and as such would be included as part of maintenance rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

Exception 4. In the LRA, the applicant took the following exception to the GALL Report program element "acceptance criteria": "NUREG-1801 recommends system and component performance test result evaluations. The IPEC Water Chemistry Control - Closed Cooling Water Program does not perform performance and functional testing."

The staff noted that the discussion of this exception in Section B.1.40 of the LRA includes a footnote, which states the following:

> While NUREG-1801, Section XI.M21, Closed Cycle Cooling Water System endorses EPRI report TR-107396 for performance and functional testing guidance, EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive CCW system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be included as part of maintenance rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

The applicant stated that the LRA indicates that Water Chemistry Control - Closed Cooling Water Program attributes 3, 4, 5, and 6 have an exception to the GALL Report. In all four cases, the exception is due to the fact that the GALL Report recommends the use of performance and functional testing to ensure acceptable function of the closed cooling water systems, while the IPEC Water Chemistry Control - Closed Cooling Water Program does not include performance and functional testing. The exception is the same regardless which revision of the EPRI guideline is used because neither revision of the EPRI guideline recommends that equipment performance and functional testing should be part of a water chemistry program. Rather, the EPRI reports state (Section 5.7 in EPRI report TR-107396 and Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry.

The staff asked the applicant for additional information to justify not performing testing and functional inspections as part of this AMP (Audit Item 97). In response, by letter dated March 24, 2008, the applicant stated that EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in

managing effects of aging on long-lived, passive closed cooling water system components. Rather, EPRI report TR-107396 states in Section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of water chemistry. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be included as part of Maintenance Rule (10 CFR 50.65) programs. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control – Closed Cooling Water Program and One-time Inspection Program through monitoring and control of water chemistry parameters and verification of the absence of aging effects.

In addition, the applicant referenced its response to the staff's request for technical justification for not including visual inspection in the program. The applicant stated in the response that the Water Chemistry Control - Closed Cooling Water Program is a preventive program. EPRI Report TR-1007820 refers to inspections performed in conjunction with maintenance activities, which are not specifically included as part of this program. However, components cooled by closed cooling water systems are routinely inspected as part of an eddy current inspection program. These heat exchangers receive a visual inspection in addition to eddy current testing that would detect aging effects and confirm the effectiveness of the Water Chemistry Control-Closed Cooling Water Program. Some of the heat exchangers receiving visual inspections include:

- IP2 and IP3 Closed Cooling Water 21/22CCHX and ACAHCC1/2
- IP2 and IP3 Instrument Air Closed Cooling Water 21/22CWHX and SWM-CLC 31/32-HTX
- IP2 and IP3 EDG Jacket Water Coolers 21/22/23EDJC and EDG-31/32/33-EDGJWHTX
- IP2 Conventional Closed Cooling 21/22THCCSHX
- IP3 Turbine Hall Closed Cooling SWT-CLC-31/32-HTX

In addition to these completed inspections, LRA Section B.1.27, One-Time Inspection, describes future inspections planned to verify effectiveness of the water chemistry control programs to ensure that significant degradation is not occurring and component intended function is maintained during the period of extended operation. This will include areas most susceptible to corrosion such as stagnant areas.

The staff reviewed EPRI Report TR-1007820 (Revision 1 to EPRI TR-107396) and determined that it does not recommend that performance and functional testing be part of the water chemistry control program. This engineering testing could be performed as part of another program. Usually, the Maintenance Rule (10 CFR 50.65) dictates the requirements of the performance and functional testing. The staff noted that a one-time inspection will be performed to verify the effectiveness of this program for managing aging in the closed loop cooling water systems in the scope of this program. The staff finds that the water chemistry control, monitoring, and inspection activities included in this program are adequate to manage the aging effects for which the program is credited without the need for performance and functional testing. SER Section 3.0.3.1.9 documents the staff's evaluation of the One-Time Inspection Program. Based on the above, the staff finds these exceptions acceptable.

The staff reviewed the applicant's evaluation and confirmed that the applicant had incorporated EPRI TR-1007820 as the technical basis guideline for its B.1.40 aging management program. The staff determined that the use of EPRI TR-1007820 provides guidance that is consistent with the recommendations in GALL AMP XI.M21, along with more detail on the various water treatment methods used at nuclear power plants, as well as control and diagnostic parameters, monitoring frequencies, operating ranges, and action levels. Therefore, the staff finds the use of EPRI TR-1007820 as the basis for this program acceptable.

Based on the above review, the staff finds the applicant's exceptions acceptable.

Enhancement 1. In the LRA and in Amendment 1 to the LRA, Attachment 2, Commitment Item 28, dated December 18, 2007, the applicant committed to implement the following enhancement to program elements "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria": "IP2: Revise appropriate procedures to maintain water chemistry of the SBO/Appendix R diesel generator cooling system per EPRI guidelines."

The enhancement is necessary to expand the scope of the program to ensure that it bounds all the components within the scope of license renewal. The enhancement does not change program content/criteria.

The staff determined that the applicant's enhancement will add water chemistry control, monitoring, and inspection activities for the IP2 SBO/Appendix R diesel generator cooling system. The enhancement will ensure that water chemistry control program activities are provided for all components on the site within the scope of the Water Chemistry control – Closed Cooling Water Program which is consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Enhancement 2. In the LRA and in Amendment 3 to the LRA, Attachment 1, dated March 24, 2008, the applicant committed to implement the following enhancement to program elements "preventive actions," "parameters monitored or inspected," "monitoring and trending," and "acceptance criteria": "IP2: Revise appropriate procedures to maintain the security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines."

The enhancement is necessary to expand the scope of the program to ensure that it bounds all the components within the scope of license renewal. The enhancement does not change program content/criteria.

The staff determined that the applicant's enhancement will add water chemistry control, monitoring, and inspection activities for the IP2 security diesel generator cooling system cooling water pH. The enhancement will ensure that water chemistry control program activities are provided for all components on the site within the scope of the Water Chemistry control – Closed Cooling Water Program which is consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Enhancement 3. In the LRA and in Amendment 3 to the LRA, Attachment 1, dated March 24, 2008, the applicant committed to implement the following enhancement to program elements "preventive actions," "parameters monitored or inspected," "monitoring and trending," and

"acceptance criteria": "IP3: Revise appropriate procedures to maintain security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines."

The enhancement is necessary to expand the scope of the program to ensure that it bounds all the components within the scope of license renewal. The enhancement does not change program content/criteria.

The staff determined that the applicant's enhancement will add water chemistry control, monitoring, and inspection activities for the IP3 security diesel generator cooling system cooling water pH. The enhancement will ensure that water chemistry control program activities are provided for all components on the site within the scope of the Water Chemistry control – Closed Cooling Water Program which is consistent with the recommendations in the GALL Report. On this basis, the staff finds this enhancement acceptable.

Operating Experience. LRA Section B.1.40 states that in June 2003 the applicant noted that the CCW corrosion inhibitor (molybdate concentration) had been out of specification 50 percent of the time since the new specification was issued in March 2003 due to dilution from water added to this system to compensate for leaks and work activities. Corrective action repaired the leaks and added chemicals to restore the molybdate concentration to specification. Detection of out-of-specification conditions and corrective action prior to loss of intended function assure continued program effectiveness in managing aging effects for passive components. Subsequently, corrosion inhibitor concentration has been satisfactory.

A QA audit of the plant chemistry program in August 2003 found the control of closed cooling water chemistry at IP2 as one of the specific areas improved since the last audit. Continuous program improvement assures continued program effectiveness in managing loss of component material.

Reports of closed cooling water chemistry control indicator (corrosion inhibitor and hardness) show that IP2 and IP3 CCW chemistry was within specification throughout 2006 except for part of May when the IP2 system was in maintenance status during refueling outage 2R17. Adherence to chemistry specifications assures continued program effectiveness in managing component aging effects.

The staff's review of operating experience indicates that this program has been effective in managing aging effects.

The staff confirmed that the "operating experience" program element satisfies the criteria in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.39 and A.3.1.39, the applicant provided the UFSAR supplement for the Water Chemistry Control - Closed Cooling Water Program. By letter dated June 12, 2009, the applicant amended LRA Section A.2.1.39 to add the IP2 instrument air system to the scope of the program. The staff reviewed these sections, as amended, and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant stated in the LRA that this program will be implemented prior to the period of extended operation (Commitment 28).

Conclusion. On the basis of its audit and review of the applicant's Water Chemistry Control - Closed Cooling Water Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report, are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the program is adequate to manage the aging effects for which it is credited. Also, the staff reviewed the enhancements and confirmed that their implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.2.17 Water Chemistry Control - Primary and Secondary Program

Summary of Technical Information in the Application. LRA Section B.1.41 describes the existing Water Chemistry Control - Primary and Secondary Program as consistent with GALL AMP XI.M2, "Water Chemistry," with enhancement.

The Water Chemistry Control - Primary and Secondary Program manages aging effects caused by corrosion and cracking mechanisms. The program monitors and controls reactor water chemistry based on EPRI TR-105714, Revision 5, "Pressurized Water Reactor Primary Water Chemistry Guidelines," and TR-102134, Revision 6, "Pressurized Water Reactor Secondary Chemistry Guidelines."

Both the EPRI primary and secondary water chemistry guidelines distinguish clearly between "control parameters" and "diagnostic parameters." Strict adherence to control parameters is expected whereas diagnostic parameters are suggested but can be plant-specific. Deviations from EPRI recommended diagnostic parameters are not exceptions to the GALL Report.

The GALL Report states that the water chemistry control is based on EPRI Reports TR-105714, Revision 3, for primary water chemistry, and TR-102134, Revision 3, for secondary water chemistry. Entergy has adopted TR-105714, Revision 5, renumbered by EPRI to Report 1002884, and TR-102134, Revision 6, renumbered by EPRI to Report 1008224.

The Revision 5 changes to TR-105714 consider the most recent operating experience and laboratory data and reflect increased emphasis on plant-specific optimization of primary water chemistry to address individual plant circumstances and the impact of the NEI steam generator initiative, NEI 97-06, which requires utilities to meet the intent of the EPRI guidelines. EPRI TR-105714, Revision 5, attempts to distinguish clearly between prescriptive and non-prescriptive guidance.

Revision 4 of TR-102134 was issued in November 1996 with increased depth of detail of the corrosion mechanisms affecting steam generators and the balance of plant and additional guidance on how to integrate these and other concerns into the plant-specific optimization process. Revision 5 provides additional details of plant-specific optimization and clarifies which EPRI guidelines are mandatory under NEI 97-06. Revision 6 provides further details on how

best to integrate these guidelines into a plant-specific chemistry program while complying with NEI 97-06 and NEI 03-08, "Guideline for the Management of Materials Issues."

Future revisions of the EPRI primary and secondary water chemistry guidelines will be adopted as required commensurate with industry standards. The One-Time Inspection Program for Water Chemistry utilizes inspections or NDEs of representative samples to verify whether the Water Chemistry Control - Primary and Secondary Program has been effective in managing aging effects.

Staff Evaluation. During its audit and review, the staff confirmed the applicant's claim of consistency with the GALL Report. As described in SER Section 3.0.2.1, the staff audited the program elements of the Water Chemistry Control - Primary and Secondary Program to verify consistency with GALL AMP XI.M2. Details of the staff's audit of this AMP are documented in the Audit Report. As documented in the report, the staff found that the Water Chemistry Control - Primary and Secondary Program elements "scope of program, preventive actions," "detection of aging effects," and "monitoring and trending," are consistent with the corresponding elements in GALL AMP XI.M2. Because these elements are consistent with the GALL Report elements, the staff finds that they are acceptable.

The staff reviewed the enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited.

The staff reviewed portions of the Water Chemistry Control – Primary and Secondary Program for which the applicant claims consistency with the GALL Report and documented an audit summary evaluation of this AMP in the Audit Report. Furthermore, the staff concludes that the applicant's Water Chemistry Control – Primary and Secondary Program reasonably assures management of aging effects so components crediting this program can perform intended functions consistent with the CLB during the period of extended operation. The staff finds the applicant's Water Chemistry Control – Primary and Secondary Program acceptable as consistent with the recommended GALL AMP XI.M2, "Water Chemistry with the enhancement as described:

Enhancement. In the LRA, the applicant committed to implement the following enhancement to program elements "parameters monitored or inspected" and "acceptance criteria": "[t]he 'parameters monitored or inspected,' will be enhanced to revise appropriate procedures to test sulfates monthly in the RWST for IP2 and "acceptance criteria," with a limit of < 150 ppb."

During the audit and review, the staff asked the applicant why the enhancement is being made for IP2 but not for IP3 (Audit Item 99). By letter dated December 18, 2007, the applicant stated that consistent with EPRI TR-105714, Rev. 5 recommendations, IP3 currently monitors RWST sulfates monthly with a limit of < 150 ppb. IP2 has not incorporated this recommendation and an enhancement is required. Thus, the enhancement does not apply to IP3. The staff finds that this enhancement is acceptable because it will follow the EPRI guidance that is recommended in the GALL Report. It is also acceptable that it does not apply to IP3 because it was previously instituted for IP3 consistent with the EPRI guidance.

Operating Experience. LRA Section B.1.41 states that a QA audit of the primary and secondary plant chemistry program in August 2003 noted that monitoring and processing requirements for primary and secondary water chemistry complied with both IP2 and IP3 technical specifications,

implementing procedures, and the IP3 technical requirements manual. In addition, the chemistry processes effectively implemented industry (e.g., EPRI and INPO) guidelines designed to extend the operating lives of primary and secondary systems and components. Continuous program improvement through adoption of evolving industry guidelines assures continued program effectiveness in managing the effects of aging on plant components.

During the audit and review, the staff asked the applicant about the frequency of the QA audits of the primary and secondary plant chemistry program. The applicant replied that the QA audits are conducted every two years. An extra audit was conducted in 2006 in addition to the regular audit in 2005 in order to adjust the audits to even years for scheduling purposes. These audits were reviewed by the staff during the onsite audit.

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

UFSAR Supplement. In LRA Sections A.2.1.40 and A.3.1.40, the applicant provided the UFSAR supplement for the Water Chemistry Control - Primary and Secondary Program. The staff reviewed these sections and determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

The applicant stated that the program enhancements will be implemented prior to entering the period of extended operation (Commitment 29).

Conclusion. On the basis of its audit and review of the applicant's Water Chemistry Control - Primary and Secondary Program, the staff determines that those program elements, for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation prior to the period of extended operation would make the existing program consistent with the GALL Report AMP to which it was compared. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3 Programs Not Consistent with or Not Addressed in the GALL Report

3.0.3.3.1 Boral Surveillance Program

Summary of Technical Information in the Application. LRA Section B.1.4 describes the existing Boral Surveillance Program as a plant-specific program.

The Boral Surveillance Program verifies whether the Boral neutron absorbers in the spent fuel racks maintain the validity of the criticality analysis in support of the rack design. The program relies on representative coupon samples mounted in surveillance assemblies in the spent fuel pool to monitor performance of the absorber material without disrupting the integrity of the storage system. Surveillance assemblies are removed from the spent fuel pool on a prescribed schedule for measurement of physical and chemical properties to assess the stability and

integrity of the Boral in the storage cells. This program applies to IP3 only because Boral is not used for criticality control of IP2 spent fuel.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.4 on the applicant's demonstration of the Boral 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 for the period of extended operation.

The staff reviewed the Boral Surveillance Program against the AMP elements found in the SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements. Specifically, the staff reviewed the following seven program elements of the applicant's program: (1)"scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," and (10) "operating experience."

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.4 states that, "the Boral Surveillance Program includes all Boral in the IP3 spent fuel pool. The IP2 spent fuel pool design does not rely on Boral for criticality control."

The staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1, since the staff confirmed that Boral was only used in IP3 spent fuel pool and IP2 uses Boraflex. Therefore, the staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.4 states that, "this is an inspection program and no actions are taken as part of this program to prevent or mitigate aging degradation."

The staff confirmed that the "preventive actions" program element satisfies the guidance in SRP-LR Section A.1.2.3.2 since IP3 has a condition monitoring program. Therefore, the staff finds this program element acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.4 states that, the program monitors changes in the following physical properties of the Boral material.

- neutron attenuation
- blister size, thickness, and location
- dimensional measurements (length, width, shape, and thickness)
- specific gravity and density

The staff confirmed that the "parameters monitored or inspected" program element satisfies the guidance in SRP-LR Section A.1.2.3.3. The staff considers this program element acceptable because experience has shown that Boral degradation in the SFP

environment occurs slowly and can be detected in the early stages by the methods proposed. The measurements of neutron attenuation, physical distortion, and weight change would detect coupon degradation that would precede a loss of functionality in the Boral panels (neutron absorption and fuel assembly spacing). Moreover, unacceptable coupon results would initiate an engineering evaluation and, if considered necessary, direct testing of the storage racks (i.e. blackness testing).

(4) Detection of Aging Effects - LRA Section B.1.4 states that "the program monitors representative coupon samples located in the spent fuel pool to determine the condition of the absorber material without disrupting the integrity of the storage system. At specified intervals, the program measures certain physical and chemical properties of removed sample coupons. From this data, the stability and integrity of the Boral in the storage cells are assessed."

The staff confirmed that the "detection of aging effects" program element satisfies the guidance in SRP-LR Section A.1.2.3.4 since the staff considers the program to collect data from representative coupon samples to assess for stability and integrity of Boral to be acceptable for detection of aging effects. Therefore, the staff finds this program element acceptable.

(5) Monitoring and Trending - LRA Section B.1.4 states that "neutron attenuation tests are trended to ensure that slow degradation has not occurred. Observable loss in neutron attenuation ability, if any, is projected to determine when neutron attenuation may fall below acceptance criteria. Size and weight measurements determine the extent of shrinkage or loss of material. This data is trended for indications of degradation. Blister shape and size are recorded and trended to determine whether new blisters are forming, the rate of growth of existing blisters, and the rate of increase in blister thickness. As blister thickness increases, it may become necessary to evaluate whether potential fuel cell deformation is a risk due to blister growth."

The staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable because the applicant monitors and trends parameters that would indicate degradation.

(6) Acceptance Criteria - LRA Section B.1.4 states that "of the measurements to be performed on the Boral, the most important are neutron attenuation measurements and dimensional measurements. Acceptance criteria for these measurements are as follows.

- Neutron attenuation testing and B-10 areal density is equal to or greater than the B-10 gm/cm^2 nominal density assumed in the criticality analysis (0.02 g/cm^2)
- Blisters are unacceptable if blister size and shape projected to the next inspection may subsume the available space between the fuel assembly and the cell wall."

In RAI B.1.4, dated December 7, 2007, the staff requested that the applicant provide additional details on the Boral Surveillance Program in regards to the neutron attenuation testing and the acceptance criteria.

In its response, by letter dated January 4, 2008, the applicant provided the following information:

- K_{eff} <0.95 is the margin to criticality used in the criticality analyses. Use of Keff <0.95 as the margin to criticality acceptance criteria is consistent with NUREG 0800.
- IP3 Boral coupon surveillance results to date have not identified any loss of neutron absorption capability between surveillance periods such that the current criterion remains acceptable for use. This is consistent with industry experience.
- IP3 has sufficient Boral coupon samples to maintain the sampling frequency through the period of extended operation.

Based on the applicant's response to the RAI describing the Boral Surveillance Program, the staff finds the applicant's response to the RAI B.1.4 acceptable. The staff's concern in RAI B.1.4 is resolved.

The staff confirmed that the "acceptance criteria" program element satisfies the guidance in SRP-LR Section A.1.2.3.6 since IP3 provided specific values for the acceptance criteria which would provide reasonable assurance that corrective actions could be taken before loss of functionality would occur. The staff finds this program element acceptable.

(10) Operating Experience - LRA Section B.1.4 states that results of an inspection of coupon samples in 2002 showed no significant degradation of Boral material. A review of this program in 2004 addressed the Seabrook Part 21 issue on Boral coupon blistering (NRC21-031006 Part 21) and led to revision of the procedure for IP3 Boral examinations to test in the next inspection (2007) the same full-length Boral sample tested in the last inspection (2002) to allow direct measurement of blister growth and to determine whether the Boral blisters have reached equilibrium.

The applicant stated that its program is based on the NUREG-1801 program description, which in turn is based on industry operating experience. Such operating experience assures continued effectiveness of the Boral Surveillance Program in managing loss of Boral neutron absorber material.

The staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10, since the operating experience supports the conclusion that the Boral Surveillance Program is effective in managing the loss of Boral neutron absorber material. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Section A.3.1.3, the applicant provided the UFSAR supplement for the Boral Surveillance Program. The staff reviewed this section and finds the UFSAR supplement information an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its technical review of the applicant's Boral Surveillance Program, the staff concludes that the applicant has demonstrated that 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 UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.2 Containment Inservice Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.8, as amended by letter dated June 11, 2008, describes the existing Containment Inservice Inspection Program as a plant-specific program.

The applicant states that the Containment Inservice Inspection Program encompasses ASME Section XI, Subsection IWE and IWL requirements as modified by 10 CFR 50.55a. The IP2 program uses the ASME Boiler and Pressure Vessel Code, Section XI, 2001 Edition, through 2003 Addenda. The IP3 program uses the ASME Boiler and Pressure Vessel Code, Section XI, 1998 Edition, no addenda. Every 10 years, each unit's program is updated to the latest ASME Section XI code edition and addenda approved in 10 CFR 50.55a. Visual inspections for IWE of surfaces for evidence of flaking, blistering, peeling, discoloration, and other signs of distress monitor loss of material of the steel containment liners and their attachments, containment hatches and airlocks, moisture barriers, and pressure-retaining bolting. Visual inspections for IWL monitor structural concrete surfaces for evidence of leaching, erosion, voids, scaling, spalls, corrosion, cracking, exposed reinforcing steel, and detached embedment. The applicant also states that the IP2 and IP3 containments are reinforced concrete structures that do not utilize a post-tensioning system; therefore, IWL post-tensioning requirements do not apply.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.8 on the applicant's demonstration of the Containment Inservice 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 for the period of extended operation.

The staff noted that the intent in writing GALL Report, Volume 2 Chapter XI was to enable an applicant to take credit for an existing mandated inspection program with minimal effort (i.e., simply identify and explain exceptions and enhancements). Entergy has identified AMP B.1.8 - Containment Inservice Inspection as being plant-specific. The staff reviewed LRA Section B.1.8 and concluded that the 10-element evaluation does not identify any differences from GALL AMPs XI.S1 (IWE) and XI.S2 (IWL). In an audit question, Entergy was requested to document an element-by-element comparison of LRA AMP B.1.8 to GALL AMPs XI.S1 and XI.S2, identifying and explaining all exceptions and enhancements to the GALL AMPs (Audit Item 26).

By letter dated December 18, 2007, Entergy indicated that the attributes of the program are compared to the ten elements of an aging management program for license renewal as described in SRP-LR, Table A.1-1. Entergy decided to describe the Containment ISI Program as a plant-specific program rather than comparing it to the GALL Report AMPs XI.S1 and XI.S2. Entergy indicated that this was done because the GALL Report programs contain many ASME Section XI table and section numbers which change with different versions of the code. Because of this, comparison with the GALL Report programs would generate many exceptions and explanations. Also, the applicable edition of the Code during the period of extended operation will be different than the edition referenced in the GALL Report.

Currently, the GALL AMPs for concrete containment, XI.S1 (for steel elements) and XI.S2 (for concrete elements) provide acceptable programs for the aging management of the containments. Using these AMPs avoids performing extensive reviews with many questions to properly evaluate the plant-specific programs. Thus, if a proposed plant-specific AMP for containments is credited, then a detailed review would be required where many items beyond those identified in the XI.S1 and XI.S2 AMPs will need to be identified. GALL AMPs XI.S1 and XI.S2 were developed based on the known provisions contained in the editions of the ASME Code, Section XI, Subsections IWE and IWL that are referenced. If a different edition of the Code is relied on and/or exceptions are taken with respect to the guidance in the GALL AMPs XI.S1 and XI.S2, then justification is needed to demonstrate adequacy. The need for additional justification is explained in the footnote to the XI.S1 and XI.S2 AMPs in GALL. This footnote states that "An applicant may rely on a different version of the ASME Code, but should justify such use." This applies to differences between the plant-specific program and the GALL XI.S1 and XI.S2 AMPs.

In the case of GALL AMPs XI.S1 and XI.S2, the acceptable code editions of Subsections IWE and IWL are those from the 1992 edition of the ASME Code, Section XI, including the 1992 Addenda, through the 2001 Code, and the 2002 and 2003 Addenda. The IP2 program uses the ASME Boiler and Pressure Vessel Code, Section XI, 2001 Edition, 2003 Addenda. The IP3 program uses the ASME Boiler and Pressure Vessel Code, Section XI, 1998 Edition, no Addenda. Every 10 years, each unit's program is updated to the latest ASME Section XI code edition and addenda approved by the Nuclear Regulatory Commission in 10 CFR 50.55a." Therefore, the editions of the Code that Entergy is using, for both IP2 and IP3, are consistent with those accepted by GALL AMPs XI.S1 and XI.S2. If, as stated in the Entergy response, there are numerous exceptions that would need to be explained, then the staff needs to be informed, in order to evaluate the adequacy of the Containment Inservice Inspection Program.

The concern noted in the Entergy response to the audit question, that the applicable edition of ASME Code, Section XI during the period of extended operation will be different than the edition referenced in the current GALL Report, is addressed in the footnote to GALL AMPs XI.S1 and XI.S2. The footnote states that "An applicant may wish to refer to the [statement of considerations] SOC for an update of 10 CFR 50.55a, to justify use of a more recent edition of the Code."

Entergy formally submitted Amendment 1 to the LRA on December 18, 2007. Under Audit Item 26, Entergy presented an element-by-element comparison to GALL AMPs XI.S1 and XI.S2. On the basis of this comparison, as discussed below, the staff finds the applicant's plant-specific Containment Inservice Inspection Program to be consistent with the GALL report.

In accordance with Entergy's decision to identify the Containment Inservice Inspection Program as a plant-specific AMP, the staff reviewed the Containment Inservice Inspection Program against the AMP elements found in the GALL Report, in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements [(1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience"].

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.8 states that the Containment Inservice Inspection Program, under ASME Section XI Subsection IWE, manages aging effects for the containment liners and integral attachments including connecting penetrations and parts forming the leak tight boundary. The applicant further states that Containment Inservice Inspection Program, under ASME Section XI Subsection IWL provides confirmation that the effects of aging on the reinforced concrete containment walls, domes, and basemats will not prevent the performance of intended functions consistent with the CLB through the period of extended operation.

The staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1. The staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.8 states that the Containment Inservice Inspection Program is a monitoring program that does not include preventive actions. The staff concurs that this is a monitoring program, and no preventive actions are required.

The staff confirmed that the "preventive actions" program element satisfies the guidance in SRP-LR Section A.1.2.3.2. The staff finds this program element acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.8 states that visual inspections for IWE monitor loss of material of the steel containment liner and its attachments by inspecting the surface for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. The applicant also states that visual inspections for IWL monitor concrete surfaces for evidence of leaching, erosion, voids, scaling, spalls, corrosion, cracking, exposed reinforcing steel, and detached embedment.

In RAI B.1.8-1 dated December 7, 2007, the staff requested that the applicant provide additional details on the condition monitoring of protective coatings in containment. In particular, the staff requested a description of the coating inspections performed on surfaces that are not included in the IWE program.

By letter dated January 4, 2008, which was further clarified during telephone conference calls held on February 7, 2008, and March 7, 2008, the applicant stated that the condition of the protective coatings on metal surfaces at IP, other than the containment liner, is monitored by Structures Monitoring Program. The Structures Monitoring Program governs monitoring the condition of structures or components of structures, including the condition of their protective coatings, as required by 10 CFR 50.65, the Maintenance Rule.

The applicant further explained that the structures are inspected every 5 years and normally inaccessible areas are inspected every 10 years. An inaccessible area is an area that requires destructive removal of a barrier for access. The containment liner insulation is also considered a barrier such that the liner plate behind it is classified as inaccessible. The scope of the inspections includes visual inspection of the coated

surfaces for signs of degradation (blistering, peeling, flaking, pinholes, rusting, splitting, and discoloration). The degradation observed during the inspections is evaluated to determine if the current condition is acceptable or further monitoring or corrective actions are necessary. Industry codes and standards including the Maintenance Rule, ASME Section XI, and building codes are used to perform these evaluations and make determinations as to whether or not the structures are capable of performing their intended functions. A structure is classified as acceptable if it is capable of performing its structural functions, including protection or support of safety-related equipment.

The inspections are performed by inspection engineers under the direction of the *responsible engineer. The responsible engineer is a degreed civil/structural engineer* with at least 10 years of related experience and a registered professional engineer. The responsible engineer and inspection engineers must be knowledgeable in the design, evaluation, and performance requirements of structures. The inspection engineers must be qualified to perform visual examination either directly or remotely to detect evidence of degradation.

The applicant clarified that protective coatings are not relied upon to manage the effects of aging for structures in License Renewal. The existing 10 CFR 50.65 Maintenance Rule Program includes monitoring the condition of coatings and they will continue to be monitored under that program during the period of extended operation.

Additionally the applicant stated that, in response to Generic Safety Issue (GSI)-191, "Assessment of Debris Accumulation on PWR Sump Performance," the Civil/Structural group visually inspects coatings in the vapor containment building during refueling outages. The frequency of the inspection will be at least once every two years or every cycle during the refueling outage. Adverse conditions will be resolved or evaluated as acceptable prior to exiting the refueling outage.

Based on the applicant's response to the RAI describing the division in responsibilities between the Structures Monitoring Program and the Maintenance Rule Program, the staff finds the applicant's response to the RAI B.1.8-1 acceptable. The staff's concern in RAI B.1.8-1 is resolved.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the guidance in SRP-LR Section A.1.2.3.3. The staff finds this program element acceptable.

(4) Detection of Aging Effects - LRA Section B.1.8 states that the primary inspection method for the steel containment liner and its integral attachments is general visual examination. Components in examination category E-A receive general visual examination or VT-3. Painted or coated areas are examined for evidence of flaking, blistering, peeling, and discoloration. Non-coated areas are examined for evidence of cracking, discoloration, wear, pitting, corrosion, gouges, and surface irregularities. Components in examination category E-C receive an augmented visual or volumetric examination in accordance with IWE Table 2500-1. The applicant also states that the primary inspection method for the concrete containment shell is a general visual examination in accordance with IWL-2500. Detailed visual examinations are performed to provide sufficient data to conduct an acceptance review when conditions exceeding

the screening criteria are noted.

The staff noted that the IP2 and IP3 containments have a somewhat unique design feature: thermal insulation on the steel liner plate, at the lower elevations of the cylindrical containment wall. In both UFSARs, this insulation is credited with limiting the liner temperature increase to 80 °F during a design basis accident. Both UFSARs state that the insulation is removable, to permit periodic inspection of the containment liner plate. In Audit Item 27, the staff asked Entergy to:

(1) Identify the AMP and describe the specific inspections performed, to ensure that this insulation will continue to perform its intended function.

(2) Describe the plant-specific operating experience related to removal of this insulation and inspection of the containment liner plate normally covered by the insulation. How does the condition of the normally insulated liner plate surface compare to the condition of the normally uncovered liner plate surface? Has augmented inspection, per Category E-C, been necessary?

In its response, dated December 18, 2007, Entergy stated:

> (1) As noted in LRA Table 3.5.2-1, the liner plate insulation jacket has no aging effect, and therefore does not require aging management.
>
> (2) IP2 and IP3 have approximately 20% of the liner inaccessible due to the insulation at the lower elevations of the containment. At the 46' Elevation, a caulking sealant, used as a moisture barrier, is installed at the junction of the bottom edges of the insulation panels and the floor to prevent moisture from reaching the steel liner. When performing a visual examination of the liner, the insulation covering portions of the containment liner is not removed. The IWE examination includes inspection of the moisture barrier to ensure that it has not degraded. IP2 and IP3 will remove insulation during the required IWE examinations if insulation removal is required to meet the requirements in Table IWE-2500-1.
>
> During the IWE first interval for IP2, corrosion was discovered on the liner during the first period (April 2000) containment inservice inspection. The corrosion existed in the portion of the liner where it is abutted by the fill slab that covers the base mat liner. A number of inspections, investigations, and evaluations were performed to determine the acceptability of the liner to perform its design function. The inspection found several areas where the moisture barrier was missing or not properly bonded between the floor slab and insulation. The degradation of the moisture barrier raised a concern relative to the condition of the liner. In order to address these concerns, IP2 selected nine (9) panels of the liner insulation for removal to facilitate augmented inspection, per Category E-C. During the removal and re-installation of these insulation panels, the opening covers are re-sealed with the caulking sealant in order to re-establish the moisture barrier.

Entergy further stated that when the insulation was removed, minor corrosion (light rust) was noted. Thickness readings were taken with no significant wall loss detected. As a result of three consecutive inspections of the nine (9) panel areas, the containment liner plate in these areas was found dry and the corrosion inactive, and the liner plate was well within the required containment liner thickness. This augmented exam was completed during the last IP2 Containment ISI interval. Entergy concluded that the IP2 liner will perform its intended function and is within acceptance limits for continued operation.

For part (a) of Entergy's response, the staff's evaluation concludes that there is no aging effect requiring an aging management program for insulation encapsulated in a stainless steel jacket and subject to an "air – indoor uncontrolled" environment. The staff accepts Entergy's AMR results.

For part (b) of Entergy's response, the staff concluded that additional information was needed before the evaluation could be completed. The staff subsequently determined, from review of Entergy documents during the audit, that insulation had been placed over the IP2 liner area that had been damaged (localized permanent deformation due to thermal expansion) by a feedwater line break in 1973. The damaged area is approximately 5′ high and 50′ around the circumference. Entergy has also treated this damaged area as inaccessible for inspection. While Entergy performed an evaluation at that time, which concluded that the permanent liner degradation would not compromise the integrity of the liner, the staff notes that the condition of the liner in the damaged area has not been examined for over 30 years.

In addition, as discussed previously, Entergy has detected some minor corrosion of the IP2 liner behind the insulation, at the juncture with the concrete floor slab. In discussions with Entergy, the staff expressed concern that similar corrosion may exist in IP3; however, Entergy has not examined the corresponding IP3 location.

Therefore, the staff requested that Entergy conduct a one-time inspection of the steel liner behind the insulation at 2 specific locations: (1) the damaged area of the IP2 steel liner; and (2) the IP3 steel liner at the juncture with the concrete floor slab, in order to confirm the absence of liner plate degradation behind thermal insulation.

The applicant provided a supplemental response to Audit Item 27 in Attachment 1 "Operating Experience – Structures" to Entergy letter dated August 14, 2008. In its response, the applicant stated that, in order to provide assurance that liner degradation is not occurring in the affected area, Entergy commits to remove insulation and perform a one-time inspection of a representative sample area of the IP2 containment liner affected by the 1973 event prior to entering the period of extended operation. Also, in order to provide further assurance that liner degradation is not occurring in the area at the juncture with the concrete floor slab on IP3, Entergy committed to perform a one-time inspection of sample locations of the IP3 containment liner at the juncture with the concrete floor slab, prior to entering the period of extended operation. These one-time inspections are documented as Commitment 35 in Regulatory Commitment List, Revision 5; Attachment 4 to Entergy letter dated August 14, 2008.

At the staff's request, the applicant has committed to perform the one-time inspections of representative samples of liner areas prior to entering the period of extended operation, to confirm the absence of any liner plate degradation behind thermal insulation. Any degradation that is detected would be dispositioned in accordance with the Containment Inservice Inspection Program, including reanalysis, repair or replacement, and fatigue analysis for IP2, if necessary. Based on this commitment, the staff considers the issue related to liner plate degradation behind thermal insulation to be resolved.

(5) Monitoring and Trending - LRA Section B.1.8 states that results are compared, as appropriate, to baseline data and other previous test results.

The staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable.

(6) Acceptance Criteria - LRA Section B.1.8 states that results are compared, as appropriate, to baseline data, other previous test results, and acceptance criteria of ASME Section XI, Subsection IWE for evaluation of any evidence of degradation. Results are compared, as appropriate, to baseline data, other previous test results, and acceptance criteria of ASME Section XI, Subsection IWL for evaluation of any evidence of degradation.

The staff confirmed that the "acceptance criteria" program element satisfies the guidance in SRP-LR Section A.1.2.3.6. The staff finds this program element acceptable.

(10) Operating Experience - LRA Section B.1.8 states that results of the IWE containment inspection at IP2 in 2004 were satisfactory.

The applicant states that an IWE containment inspection at IP3 in 2005 detected minor surface corrosion classified as "acceptable" under the program definitions.

The applicant also states that an IWL inspection at IP2 in 2005 revealed 91 recordable indications reviewed by engineering. None of these indications, which were compared to the results of the 2000 inspection, represented a structural concern. An IWL inspection at IP3 in 2005 found minor spalling and other indications noted in the 2001 inspection with no signs of further degradation. Absence of degradation that could lead to failure, demonstrated through regular program inspections, assures effective program management of aging effects for passive components.

The applicant further states that a self-assessment of the Containment ISI program in October 2004 found all findings and recommendations from earlier EPRI assessments of the program evaluated and corrected. Detection of program weaknesses and subsequent corrective actions assure continued program effectiveness in managing component aging effects.

The staff noted that in 1973 a significant permanent deformation of the IP Unit 2 liner plate occurred at the penetration for feedwater line #22, as described in LRA Section 4.6. However, the operating experience element of AMP B.1.8 does not discuss

this existing condition, nor the results of periodic inspections conducted under the Containment ISI Program. In Audit Item 30, the staff asked Entergy to:

(a) Describe in greater detail the event that resulted in the permanent liner plate deformation. When specifically did it occur? What was identified as the root cause? How was this corrected?

(b) Discuss the history of ISI of the permanently deformed liner plate, from 1973 to the present.

In its response, dated December 18, 2007, Entergy stated:

(a) The permanent IP2 liner plate deformation occurred on November 13, 1973 as a result of a break in the feedwater line to Steam Generator No. 22 inside the containment near the feedwater line penetration. The pipe break resulted in a slight bulge, which apparently was caused by the steam and water jet impingement. This was corrected by pressurizing the containment which caused the liner to move 5/8 of an inch at 15 psig and no further during pressurization to 47 psig. Also, a number of modifications were made to prevent water hammers in these lines and to improve the piping and liner ability to withstand such forces. These included rerouting the pipe layout, installing additional pipe supports, installing "J Tubes" to delay the draining of the feedwater rings, and installing additional insulation above the pipe break area around the inside of the containment. In addition, analyses were performed of the liner plate and pipe material, and some experimental verification was conducted.

(b) In 2004, general visual examinations were performed for all accessible areas of the containment liner, including penetrations and airlocks as part of the Containment Inservice Inspection Program. Some minor surface corrosion and/or coating deterioration were observed on the penetrations. Entergy concluded that this is general surface corrosion that did not result in any significant loss of material. A containment leak rate test at IP2 was completed satisfactorily in 2006.

Further staff evaluation of this condition is contained in the "Detection of Aging Effects" discussion above. Entergy has committed to inspect the damaged liner area, which was covered by insulation after the accident, to confirm the absence of liner degradation, prior to entering the period of extended operation.

The staff reviewed the discussion of operating experience for the existing, plant-specific Containment Inservice Inspection Program as given in the PBD. In a condition report, the staff noted that it stated, "The south side of the Containment dome in the alley between the Fan building and VC about 25 feet up is spalling in about 6-7 places. The rebar is exposed to the elements and is showing signs of rust. The openings into the concrete are about 12-14 inches."

IP2 Containment Spalling (Audit Item 361)

In Audit Item 361, the staff asked Entergy to provide additional details, including any commitments for augmented inspection during the period of extended operation. In its response, dated March 24, 2008, Entergy stated that this condition was first noted

during the 2000 IWL inspection. The 2005 IWL inspection found little or no change from 2000. The spalls occur at locations where Cadweld™ sleeves have insufficient concrete cover, attributed to an original installation deficiency. Rusting is not active and spalls are in an area where the rebar stresses are low. Entergy indicated that Raytheon has evaluated the structural margins for the IP containments, and at the locations of the exposed rebar, there is sufficient margin to accommodate additional loss of material due to corrosion. The condition is being monitored under the IWL program. Remedial action will be taken if the spalls further degrade and affect structural integrity.

Entergy identified several inspection enhancements, beyond general visual inspection, that are being implemented to more accurately measure the extent and progress of degradation. However, there is no commitment to continue this augmented inspection during the period of extended operation. In follow-up discussions regarding Audit Item 361, the staff requested Entergy to (1) provide the technical basis why augmented inspection during the extended period of operation is not necessary; and (2) provide its rationale for not proactively precluding progression of the concrete spalls and rebar rust/corrosion during the period of extended operation, by taking reasonable action to remedy this condition.

The applicant provided its supplementary response in a letter dated August 14, 2008. In its response, the applicant stated:

> Concrete spalls on the containment were noted during the 2000 containment inservice inspection. In these areas, the exposed reinforcing steel is oxidized, forming a protective coating. These areas have been evaluated under the corrective action program. The evaluations have determined that the spalls occur at locations where cadweld sleeves have insufficient concrete cover. Cadweld splices have diameters larger than the bar and thus have the least amount of concrete cover. The spalled concrete locations are on the vertical cylinder wall of the containment precluding the possibility of standing water that could percolate through the concrete. The location on the vertical wall of containment precludes ready access to allow for repair of a condition determined to have no impact on the ability of the structure to perform its required function.
>
> The 2005 CII-IWL inspection found little or no change of the condition observed in 2000. The identified areas show no signs of corrosion staining or deterioration and no indication that the degradation is progressing.
>
> During the LRA review, Entergy committed to enhance the CII-IWL inspections during the period of extended operation through enhanced characterizing of the degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) (Ref. audit question 533). This better quantification will allow for more effective trending of degradation following future inspections. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual

> inspections. Implementation of this enhancement requires the continued use of optical aids to allow effective characterization of indications on the containment wall that are not accessible from the ground or from existing structures.
>
> While Entergy has observed no progression of the containment concrete spall and rebar corrosion conditions during the most recent periodic inspections, the enhanced measures for characterizing degradation during the period of extended operation provide an effective means to detect potential future progression of the degradation such that corrective action to remedy the condition can be taken prior to loss of the license renewal intended function. [Commitment 37]

The staff's evaluation of Entergy's supplemental response concluded that the applicant's commitment to use enhanced inspection techniques to better characterize and monitor the degradation is a positive step; however, the applicant had not committed to take remedial action to fix the degraded areas. Therefore, the staff determined that it needed additional clarification of how Entergy plans to implement aging management during the license renewal period.

In a telephone call with the applicant on September 3, 2008, the staff requested additional relevant information for the IP2 and IP3 containments on the existing design margins at the locations of observed degradation, identifying the specific locations and dimensions of the damage. By letter dated November 6, 2008, the applicant submitted a supplemental response to Audit Item 361, describing the design margins for the IP containment structures at the locations of existing concrete degradation. At the time of issuance of the SER with Open Items, the staff was in the process of reviewing the applicant's response. Thus, this issue was identified as Open Item 3.0.3.3.2-1.

In its response dated November 6, 2008, the applicant stated:

> Spalling of concrete has been observed on IP2 containment exterior surface. The affected areas are the vertical wall.
>
> The containment structure is designed to withstand seismic, wind, deadweight, pressure, and temperature forces caused by natural phenomena and accident conditions. In addition, the integrated leak rate test is periodically performed on the containment which imposes an internal nominal pressure of 47 psi.
>
> Margin is defined as the difference between the Code allowable forces/stresses and the actual forces/stresses in the structure caused by the most severe loading condition. Meeting the Code provides margin in the form of a safety factor that requires the design strength of the structure to be a multiple of the strength necessary to prevent failure under maximum load conditions. Over and above the safety factor established by meeting Code requirements is margin between actual strength and the strength required to just meet the Code.

All areas of the spalled concrete on the containment structure exceed the strength required to meet Code requirements. The margin available over and above the Code requirements is shown in the following table. As the surface concrete is not credited for tensile strength of the structure, the spalling has no impact on the available margins.

Elevation (ft above ground)	Margin above Code allowable (%)	
	Vertical rebar	Horizontal rebar
191.0	51	32
117	58	38
64	52	51
45.7	37	100

Since the design of the IP3 containment is similar to the IP2 containment design, the margins developed for IP2 are applicable to IP3."

The applicant also tabulated the approximate location (elevation and azimuth), dimensions of spall and the design margin for each spalled area for IP2 and IP3 in its above response.

The staff reviewed the applicant's response dated November 6, 2008, and concluded that the staff required additional clarification before it could determine that the applicant's proposed aging management program for the period of extended operation is sufficient. This issue was identified as Open Item 3.0.3.3.2-1.

In an effort to resolve this open item, the staff issued follow-up RAI 3: Open Item 3.0.3.3.2-1 (Audit Question 361), dated April 3, 2009, which requested the following:

(a) The clarification for the IP containment spalling states: 'As the surface concrete is not credited for tensile strength of the structure, the spalling has no impact on the available margins.' The strength margins identified appear to be based on the nominal rebar dimensions, without any consideration for rebar degradation due to exposure and potential loss of bond between the concrete and the rebar. Explain how the existing degradation and design margin will be considered in performing periodic inspections to monitor degradation that would ensure that there is no loss of containment intended function during the period of extended operation.

(b) In the spent fuel pool discussion, in the letter dated November 6, 2008, the applicant stated: '[l]ittle or no corrosion was observed in the rebar except at a location in the wall where spalling had occurred exposing rebar to the elements. Analysis of the rust particles showed high chloride content and, low boron concentration indicating that rainwater was the primary cause of the observed corrosion.' The applicant is requested to provide the

technical basis for the adequacy of the 5-year IWL frequency of inspection of the degraded areas of the IP containments during the period of extended operation, considering the possibility of an increased site-specific corrosion rate of the exposed rebar on the containments. This should include results of prior inspections, including any available comparative photos showing the progression of degradation.

By letter dated May 1, 2009, Entergy responded to follow-up RAI 3: Open Item 3.0.3.3.2-1 (Audit Question 361), stating as follows:

(a) As stated in Letter NL-08- 169, dated November 6, 2008, the existing surface concrete degradation and potential loss of bond between the concrete and the rebar has no impact on the ability of containment to perform its intended function during the period of extended operation. The design margins in containment are such that loss of one bar in every 4.5 feet in the vertical direction would not impact the ability of containment to perform its intended function.

The ISI-IWL inspections have confirmed that there has been no identified degradation that could result in loss of function of the containment structure (rebar and concrete) due to aging effects. Localized surface rust has been observed at containment areas where rebar has been exposed, but these visual inspection results show no discernable deviation of rebar dimensions from nominal. No degradation has been observed that indicates loss of bond for rebar that is not monitored directly.

As part of the IPEC corrective action program (i.e., program Element 7), if degradation is identified during inspections, the impact of the degradation on design margin will be evaluated to ensure that there has been no loss of containment intended function.

Evaluations performed on containment associated with potentially degraded rebar (i.e., localized surface degradation) have shown that loss of a number of reinforcing bars would have an insignificant effect on containment stress margins and would not impact containment intended function. Degradation of the rebar will be readily discernable as obvious changes in bar dimensions well before such degradation could progress to the point of challenging the available design margins.

(b) The technical adequacy of the 5-year IWL frequency of inspection of the degraded areas of the IPEC containments has-been demonstrated by past inspection results. No detectable changes have occurred over the 5-year period between past inspections.

The rate of degradation of the exposed rebar of the containments has been imperceptible.

Documented inspection history for the first period IWL inspection began in 1999. Photographs taken of exposed rebar in the most recent inspection in 2009 were compared to photographs taken during the first IWL interval inspection in 2000 and a subsequent inspection in 2005. As can be seen from the photos in Figures 5 through 7 corrosion of the exposed rebar is almost nonexistent with no noticeable change in appearance over the years. Spalling is confined to a small area around the rebar with no noticeable cracking being present, which would indicate that the degradation is localized or has not progressed along the length of the rebar creating the potential for more spalling. Therefore, based upon past and recent inspection, increased corrosion rates have not been identified and additional degradation, which could prevent the containment from performing its intended function, would be readily detected by the established IWL inspections.

The staff reviewed the applicant's May 1, 2009 response to follow-up RAI 3: Open Item 3.0.3.3.2-1 (Audit Question 361), and the applicant's previous responses concerning the spalling of the IP2 containment exterior surface. The staff noted the following:

- Spalling on the external surface of the IP2 concrete containment was first documented during the 2000 ASME Subsection IWL inservice inspection. The spalls occurred in the vertical reinforcing steel at locations where the reinforcing bars are spliced using Cadweld sleeves. The diameter of the Cadweld sleeves is about two times that of the reinforcing bars.

- The 2005 IWL inspection of the IP2 containment found little or no change in the conditions observed previously during 2000.

- The most recent inspection of the IP2 containment, during 2009, using enhanced remote visual optical aids indicated little, if any, additional degradation of the concrete and reinforcing steel since 2000. This is based on a comparison of photographs taken during 2000 and 2009 of the same areas.

- According to the applicant's analysis and evaluation, the design margin provided at IP2 is at least 37 percent more than what is required by the design code. Currently, the surface corrosion on the exposed Cadweld sleeves is the only observed degradation. This degradation is insignificant when compared to the available margin.

Based on the regular IWL inspections conducted every 5 years, and the use of enhanced remote visual aids to monitor and trend the currently degraded locations, there is reasonable assurance that any additional degradation of the IP2 concrete containment would be identified prior to a loss of intended function. If additional degradation of the IP2 containment is detected during the period of extended operation,

the degradation will be evaluated and resolved in accordance with the Containment Inservice Inspection Program. Therefore, the staff concludes that the effects of aging on the IP containment concrete will be adequately managed in accordance with 10 CFR 54.21(a)(3). On this basis, Open Item 3.0.3.3.2-1 is closed.

UFSAR Supplement. In LRA Sections A.2.1.7 and A.3.1.7, the applicant provided the UFSAR supplement for the Containment Inservice Inspection Program. The staff reviewed these sections and finds the UFSAR supplement information provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

By letter August 14, 2008, the applicant added Commitment 37 to enhance the Containment Inservice Inspection Program to include inspections of the containment using enhanced characterization of degradation during the period of extended operation.

Conclusion. On the basis of its technical review of the applicant's Containment Inservice Inspection Program, and review of the applicant's responses to the staff's RAIs, the staff concludes that the applicant has demonstrated that 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 UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.3 Heat Exchanger Monitoring Program

Summary of Technical Information in the Application. LRA Section B.1.17 describes the existing Heat Exchanger Monitoring Program as a plant-specific program.

The Heat Exchanger Monitoring Program inspects by visual or other NDE techniques heat exchangers for loss of material. Inspection of heat exchanger (HX) tubes is at frequencies based on plant- and application-specific history, heat exchanger operating conditions, and heat exchanger availability. Inspection frequencies may be changed based on engineering evaluation of inspection results.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.17 on the applicant's demonstration of the Heat Exchanger 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 for the period of extended operation.

The staff reviewed the Heat Exchanger Monitoring Program against the AMP elements found in the GALL Report, in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements ((1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience").

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.17 states that the Heat Exchanger Monitoring Program manages loss of material on selected heat exchangers required for efficient and reliable power generation. Steam generators are not included in this program.

The applicant indicated it will enhance the applicable procedures of the existing program, to include the following heat exchangers in the scope of the program:

- safety injection pump lube oil heat exchangers
- RHR heat exchangers
- RHR pump seal coolers
- non-regenerative heat exchangers
- charging pump seal water heat exchangers
- charging pump fluid drive coolers
- instrument air heat exchangers (IP3 only)
- spent fuel pit heat exchangers
- secondary system steam generator sample coolers
- waste gas compressor heat exchangers
- SBO/Appendix R diesel cooling water heat exchangers (IP2 only)

By letter dated December 18, 2007, in response to Audit Item 52, Entergy described the heat exchangers currently included in the existing program, which is called the Eddy Current Program. Appendices 1 and 2 of the program document provide the detailed list of the heat exchangers for units 2 and 3, respectively.

Additionally, Entergy provided a description identifying the correlation between the HX tubes listed in AMR Tables 3.3.2-1 through 3.3.2-16 and those listed in the scope section of the AMP. In response to this question, Entergy also indicated that it needs to revise the LRA to address two items as follows: (1) the line item in AMR Table 3.3.2-2 IP3 Service Water refers to the instrument air copper alloy heat exchangers IP3 SWN CLC 31/32 HTX. Including this heat exchanger as part of the enhancement is not appropriate since these are already in the existing eddy current inspection program; (2) the LRA needs to be revised to include the charging pump crankcase oil cooler (IP3-CHRG PP31/32/33 CRANK HTX).

The staff reviewed the response and determined that, with the two corrections noted above, there is a match between the applicable heat exchangers listed in AMR Tables 3.3.2-1 through 3.3.2-16 and those listed in the scope section of the AMP. The staff confirmed that Entergy formally amended the LRA, by letter dated December 18, 2007, to incorporate these corrections.

By letter dated December 18, 2007, in response to Audit Item 56, Entergy indicated that this AMP manages the aging effect of loss of material due to wear for the HX tubes included in the scope. Some of the heat exchangers are classified as ISI Class 1, 2, & 3 and do fall under the jurisdiction of ASME, Code Section XI inservice inspection and

repair/replacement requirements associated with the pressure boundary. The heat exchanger monitoring program does not implement any of the repair/replacement or inspection activities of these codes.

During the review of the Eddy Current Program, the staff noted that Section 2.2 of the program indicates that the IP Eddy Current Program is not part of the ASME Section XI ISI/inservice testing programs. Section 2.2 also states that the ASME Code does not mandate BOP heat exchanger eddy current inspections. Therefore, inspections are not performed for specific compliance with any ASME Code, Section V or XI requirements. ASME Code, Section V, Article 8, Appendix I is utilized for the development of OD flaw calibration standards.

Based on the description of the heat exchangers included in the existing Eddy Current Program and the additional heat exchangers listed as enhancements, the staff determines that the scope of this AMP includes all components which credit this AMP in the AMR.

The staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1. The staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.17 states that this is an inspection program and no actions are taken as part of this program to prevent degradation.

The staff confirmed that the "preventive actions" program element satisfies the guidance in SRP-LR Section A.1.2.3.2. The staff finds this program element acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.17 states that visual or other non-destructive examinations of shell-and-tube HX tubes are performed to determine tube wall thickness, thereby managing the aging effect of loss of material. The applicant indicated it will enhance appropriate procedures, to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current testing, is not possible due to heat exchanger design limitations.

By letter dated December 18, 2007, in response to Audit Item 53, Entergy explained that the wear that is identified by this aging effect occurs on the outside of the tubes due to contact between the tubes and the tube support plates. This wear may be caused by vibrations of the tubes because of high flows or excessive clearance between the tubes and the tube support plates. Wear due to abrasive fluid at high velocity is not expected due to the controlled water chemistry of the fluids on the shell and tube sides. The staff determined that the eddy current testing or visual inspection methods described in this AMP could be used to monitor the wall thickness of the HX tubes to detect the presence of and extent of the loss of material.

By letter dated December 18, 2007, in response to Audit Item 54, Entergy indicated that all of the heat exchangers in the existing program are large enough so that eddy current testing of the tubes can be performed. Visual inspections are not performed routinely. Some of the new heat exchangers added in the enhancement are small, and thus may preclude the possibility to perform eddy current testing. In these cases visual inspection

would be needed. The staff concurs that, for those heat exchangers that are not large enough to perform eddy current testing, visual inspection of the tubes for wall loss is an acceptable method to detect loss of material.

By letter dated December 18, 2007, in response to Audit Item 55, Entergy indicated that if eddy current testing of the tubes is not practical due to the size of the heat exchanger, configuration, and tube size, then a remote visual inspection of the tubes may be required. The remote visual examination may be performed using a fiberscope placed inside the tubes or on the tube exterior from the shell side. The specific acceptance criteria of the program will be revised to require that no unacceptable signs of degradation are present. This was identified as Commitment 10. The eddy current tests have an acceptance criterion, which is determined by engineering evaluation on a heat exchanger-specific basis. The staff concludes that the use of remote visual examination methods by a fiberscope placed inside or on the outside surface of the tubes could detect loss of material of the HX tubes, and thus is acceptable. The specific acceptance criterion for the visual inspection consisting of no unacceptable signs of degradation is considered acceptable because it would identify any loss of material of the tube walls. The inclusion of the acceptance criterion for visual inspection of the tubes is a new enhancement to the existing program. Entergy has formally submitted Commitment 10, as part of an LRA amendment.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the guidance in SRP-LR Section A.1.2.3.3. The staff finds this program element acceptable.

(4) Detection of Aging Effects - LRA Section B.1.17 states that loss of material is the aging effect managed by this program. Representative tubes within the sample population of heat exchangers are inspected at a frequency determined by plant-specific and industry operating experience to ensure that effects of aging are identified prior to loss of intended function. An appropriate sample population of heat exchangers is determined based on operating experience prior to inspections. The sample population of heat exchangers is determined based on the materials of construction of the HX tubes and the associated environments as well as the type of heat exchanger (for example, shell and tube type). Inspection can reveal loss of material that could result in degradation of the HXs. The applicant indicated it will enhance appropriate procedures, to include consideration of material-environment combination when determining sample population of heat exchangers.

Components whose inspection results continually indicate no new indications from previous inspections are candidates for inspection frequency lengthening. Conversely, the inspection frequencies for components with indications of an increasing trend when compared to previous inspections are evaluated for an increase in inspection frequency.

The staff reviewed Section 2.4 of the applicant's Eddy Current Program and noted that the eddy current inspection frequencies are described therein. Appendices 1 and 2 list the specific inspection frequencies for each heat exchanger. Section 2.4 states that the frequencies are based on plant-specific and application-specific knowledge, as well as past history, current HX operating conditions, and unit availability/outage schedules. The

existing program also indicates that the established intervals are selected in order to uncover potential tubing problems before failure occurs.

The staff also reviewed Section 2.5 of the Eddy Current Program and noted that the program defines the sampling plan. In general, all of the tubes will be inspected for small HXs. For other HXs, the sampling size depends on the material of the HX tubes and the specific operating experience of the HX. Based on the enhancement described above, the material-environment combination will also be considered when determining sample population of HXs. Appendices 1 and 2 of the Eddy Current Program list the approximate sampling size in percentages of the total number of tubes for each HX. When less than a 100% inspection is performed, the program indicates that efforts be made to ensure that the tubes randomly selected during each inspection are different from the previously inspected tubes in order to approach a 100% inspection of the tubes over the many inspections performed.

As noted in Section 2.13 of the Eddy Current Program, the eddy current vendor provides reports which contain the results of the inspections. A record of all inspections for each component in the program is maintained on an on-going basis.

The staff finds that the eddy current inspection frequencies, sampling plan, and data collection, as summarized above, is appropriate for detecting loss of material before there is a loss of the component intended function, and thus this program element is acceptable.

The staff confirmed that the "detection of aging effects" program element satisfies the guidance in SRP-LR Section A.1.2.3.4. The staff finds this program element acceptable.

(5) Monitoring and Trending - LRA Section B.1.17 states that results are evaluated against established acceptance criteria and an assessment made regarding the applicable degradation mechanism, degradation rate and allowable degradation level. This information is used to develop future inspection scope, to modify inspection frequency, or replacement of the component if appropriate. Wall thickness is trended and projected to the next inspection. Corrective actions are taken if projections indicate that the acceptance criteria may not be met at the next inspection.

The staff confirms that the existing program contains monitoring and trending criteria for the HXs. The criteria require that an estimate of the HX remaining service life be made based on the inspection results. The inspection results are compared with previous successive data in order to estimate the growth rate of the tube damage. If the growth rate for a particular tube is estimated to result in the tube exceeding the established plugging criteria prior to the next scheduled inspection, the tube will be plugged as a precautionary measure. The description included in the existing program ensures that monitoring and trending is performed for the collected data and that the data are properly evaluated to determine whether corrective actions are needed before a loss of the HX intended function would occur.

The staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable.

(6) Acceptance Criteria - LRA Section B.1.17 states that the minimum acceptable tube wall thickness for each HX inspected is based upon a component-specific engineering evaluation. Wall thickness is acceptable if greater than the minimum wall thickness for the component.

The applicant indicated it will enhance appropriate procedures, establishing the minimum tube wall thickness for the new HXs identified in the scope of the program; and revise appropriate procedures, establishing acceptance criteria for HXs that are visually inspected, to include no unacceptable signs of degradation.

The staff reviewed the acceptance criteria presented in the existing plant program, which define the maximum acceptable tube wall loss for HX tubes, in order to determine whether tube plugging is required. The existing program notes that ASME Section XI does not provide code-allowable minimum wall thickness requirements for HX tubes. Therefore, the existing program utilizes the EPRI guidance for determining the tube plugging criteria. Appendices 3 (for IP2) and 4 (for IP3) of the Eddy Current Program present a summary table for the allowable wall loss percentage for the HXs, based on the EPRI guidance documents. In addition to the tube wall loss criteria, the existing program also provides HX replacement criteria. The program states that a HX and/or tube bundle will be identified for replacement if tube plugging has reached 10 percent or more of the total number of tubes, unless a specific calculation has been previously prepared to the contrary. Inspection results of HX tubes will be compared with previous successive data in order to estimate a growth rate of the tube damage. The growth rate for a particular tube is determined to establish the plugging criterion prior to the next scheduled inspection to determine whether the tube will be plugged as a precautionary measure. A formula is provided in the existing program, which is used as a trending tool to estimate the tube remaining life in terms of the number of refueling cycles.

The existing program will be enhanced to include the minimum wall thickness for the new HXs added to the scope of the program, and to specify that if visual examination is performed, the acceptance criterion is "no unacceptable signs of degradation." The acceptance criteria for the eddy current tests based on minimum wall thicknesses are acceptable. However, the staff determined that the acceptance criteria for visual examination are not clear and appear to be subjective; Entergy needs to clarify, preferably in quantitative terms, what acceptance criteria are used for the visual examination of the HX tubes. In RAI 3.0.3.3.3–1, the staff requested that Entergy define the visual inspection acceptance criteria in greater detail. Pending receipt and review of the applicant's response, this was identified as Open Item 3.0.3.3.3–1.

By letter dated December 30, 2008, the staff requested that Entergy clarify, in quantitative terms, which acceptance criteria are used for the visual examination of the HX tubes.

By letter dated January 27, 2009, the applicant stated that the visual examinations of the HX tubes will be performed by a qualified engineer and will focus on the detection of loss of material that might be induced by erosion, wear, corrosion, pitting, fouling or scaling. The applicant also stated that the term "no acceptable signs of degradation" means no detection of these mechanisms such that the intended function of the HXs would be impaired. The applicant also clarified that if evidence of any of these

mechanisms were to be noted by the qualified HX engineer, the engineer would base his evaluation of the degraded condition on design requirements and thickness of the HX tubes when taking into account the surface conditions caused by corrosion, erosion, pitting or wear, and or any scale or other foreign materials noted on the tubes.

The staff noted that ASME Code, Section XI cites VT-3 and VT-1 visual examination methods as acceptable visual examination methods for detecting surface discontinuities or imperfections in plant components, including those that might be indication of wear, erosion, corrosion (including pitting corrosion). The staff finds this to be acceptable because the applicant will be performing visual examinations of these HX tubes using methods that are capable of detecting surface discontinues or imperfections in the HX tubes and because the applicant will base acceptance of any relevant condition on the design requirements and thickness of the tubes. The staff concludes that RAI 3.0.3.3.3-1 is resolved and Open Item 3.0.3.3.3-1 is closed.

The staff confirmed that the "acceptance criteria" program element satisfies guidance in SRP-LR Section A.1.2.3.6. The staff finds this program element acceptable.

(10) Operating Experience - LRA Section B.1.17 states that results of eddy current testing of the tubes for several different IP2 HXs during 2000 through 2006 have indicated which tubes should be plugged, thus preventing the loss of the pressure boundary intended function. Detection of degradation, followed by corrective action prior to loss of intended function, proves that the program effectively manages aging effects for passive components.

A review of the IP2 HX inspection plan in September 2003 compared the scope of the IP2 inspections planned for refueling outage 2R16 (2004) against the typical scope of inspections planned for an IP3 refueling outage, and implemented recommended changes in the IP2 inspection scope. Use of shared best practices in the development of inspection plans assures continued program effectiveness in managing aging effects for passive components.

Results of eddy current testing of the tubes for several different IP3 HXs from 1997 through 2004 have indicated which tubes should be plugged, thus preventing the loss of the pressure boundary intended function. Detection of degradation and corrective action prior to loss of intended function prove that the program effectively manages aging effects for passive components.

An ongoing plan from a review of inspection intervals for IP3 components in April 2003 includes programmatic and technical activities for a wide range of HXs at IP3 to track improvements and corrective actions for the program. Detection of program weaknesses and subsequent corrective actions assure that the program will continue to manage loss of component material effectively.

The staff reviewed the program basis document discussion of operating experience for more information on applicable operating experience. The program basis document discussed the results of past eddy current testing of the tubes for several different IP2 and IP3 HXs, which resulted in the plugging of certain tubes.

The staff also reviewed a results report that was referenced in a program basis document. This document contains an IP3 Eddy Current Program Heat Exchanger Listing, which presents results from past operating experience of the tubes for different IP3 HXs during the period 1997 through 2004. The review of this table confirmed that the program is able to identify aging effects of loss of tube thickness before the loss of the pressure boundary intended function, and that corrective action was taken by plugging the appropriate tubes. This reference also has examples where the eddy current test frequency was increased (e.g., changed from once per eight years to once per two years in July 2000 for a particular HX), which demonstrates that the frequency of inspection is revised based on the operating experience.

The staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.16 and A.3.1.16, the applicant provided the UFSAR supplement for the Heat Exchanger Monitoring Program. The staff reviewed these sections and finds the UFSAR supplement information an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Heat Exchanger Monitoring Program, the staff concludes that the applicant has demonstrated that 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 UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.4 Inservice Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.18, as amended by letter dated June 11, 2008, describes the existing Inservice Inspection Program as a plant-specific program.

LRA Section B.1.18 states that the Inservice Inspection Program encompasses ASME Section XI, Subsections IWA, IWB, IWC, IWD, and IWF requirements and 10 CFR 50.55a imposes ISI requirements of ASME Code, Section XI, for Classes 1, 2, and 3 pressure-retaining components, their attachments, and supports in light-water cooled power plants. Inspection, repair, and replacement of these components are addressed in Subsections IWA, IWB, IWC, IWD, and IWF. The program includes periodic visual, surface, and volumetric examination and leakage tests of Classes 1, 2, and 3 pressure-retaining components, their attachments, and supports.

ISI of supports for ASME piping and components is addressed in ASME Code, Section XI, Subsection IWF, which constitutes a mandated program for aging management of ASME Classes 1, 2, 3, and MC supports for license renewal. The program uses NDE techniques to detect and characterize flaws. Three types of examinations used are volumetric, surface, and visual. Volumetric examinations use radiographic, ultrasonic, or eddy current methods to locate surface and subsurface flaws. Surface examinations use magnetic particle or dye penetrant testing to locate surface flaws.

Three levels of visual examinations are specified. VT-1 visual examination, which assesses the surface condition of the part examined for cracks and symptoms of wear, corrosion, erosion, or physical damage, can be by either direct or remote visual observation using various optical/video devices. The VT-2 examination specifically locates evidence of leakage from pressure-retaining components (period pressure tests). While the system is under pressure for a leakage test, visual examinations detect direct or indirect indication of leakage. The VT-3 examination determines the general mechanical and structural condition of components and supports and detects discontinuities and imperfections. The Inservice Inspection Program is based on the ASME Section XI Inspection Program B (IWA-2432), which has 10-year inspection intervals. Every ten years the program is updated to the latest ASME Code, Section XI edition and addenda in 10 CFR 50.55a.

IP2 entered the fourth ISI interval on March 1, 2007. The ASME Code edition and addenda for the fourth interval for IP2 is the 2001 Edition with 2003 addenda. IP3 is currently in the third ISI interval. The ASME Code edition and addenda for IP3 is the 1989 Edition with no addenda. The program consists of periodic volumetric, surface, and visual examination of components and their supports for assessment, signs of degradation, flaw evaluation, and corrective actions. Augmented ISIs are also included as required by 10 CFR 50.55a, the staff, responses to requests for additional information, or as necessary under the program.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.18 on the applicant's demonstration of the Inservice 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 for the period of extended operation.

The staff noted that the applicant has categorized its Inservice Inspection Program as a "plant-specific" program.

The staff reviewed the Inservice Inspection Program against the staff's recommended program element criteria that are provided in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1. The staff focused its review on assessing how the plant-specific program elements for the Inservice Inspection Program would ensure adequate aging management when compared to the recommended program element criteria that are given in SRP-LR Section A.1.2.3. Specifically, the staff reviewed the following eight program elements of the applicant's program: (1)"scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," and (10) "operating experience."

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," are part of the site-controlled QA program. The staff's evaluation of the applicant's Quality Assurance Program is documented in SER Section 3.0.4.

The staff's evaluation of the remaining program elements are given in the paragraphs that follow:

(1) Scope of the Program - LRA Section B.1.18 states that "[t]he ISI Program provides the requirements for ISI, repair, and replacement. The components within the scope of the

program are specified in Subsections IWB-1100, IWC-1100, IWD-1100, and IWF-1100 for Classes 1, 2, and 3 components and supports, Quality Groups A, B, and C respectively, and include all pressure-retaining components and their integral attachments. The components described in Subsections IWB-1220, IWC-1220, and IWD-1220 are exempt from the examination requirements of Subsections IWB-2500, IWC-2500, and IWD-2500.

The ISI Program manages cracking for carbon steel, carbon steel with stainless steel cladding, and stainless steel components, including bolting. The ISI Program implements applicable requirements of ASME Code, Section XI, Subsections IWA, IWB, IWC, IWD, IWF and other requirements specified in 10 CFR 50.55a with approved NRC alternatives. The ISI Program also manages reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel. Both IP2 and IP3 use ASME Code Case N-481 as approved in Regulatory Guide 1.147 for managing the effects of loss of fracture toughness due to thermal aging embrittlement of CASS pump casing pressure retaining welds. ASME Code Case N-481 has been incorporated in later editions of the code and IP2 will not reference Code Case N-481 in the 4th interval."

SRP-LR Section A.1.2.3.1 states, "[t]he specific program necessary for license renewal should be identified. The scope of the program should include the specific structures and components of which the program manages the aging."

The staff noted that the requirements for inservice inspection program are mandated by the provisions in 10 CFR 50.55a. The staff verified that the rule requires U.S. licensees to establish inservice inspection (ISI) programs for their ASME Code Class components, structures, and component supports and requires U.S. licensees to apply the ISI requirements that are provided in the provisions of the ASME Boiler and Pressure Vessel Code, Section XI, Division 1 (henceforth ASME Code, Section XI), Subsections IWA, IWB, IWC, and IWD for the AMSE Code Class 1, 2, and 3 components, in Subsection IWF for ASME Code Class component supports, and in Subsection IWA for generic ISI requirements. The current edition of the rule permits use of ASME Code, Section XI editions through 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda.

In LRA Amendment 5, dated June 11, 2008, the applicant amended AMP B.1.18 to clarify that the applicable edition credited for aging management of ASME Code Class components at IP2 within the scope of the AMP is the 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda. Although the Inservice Inspection Program is a plant-specific AMP for the LRA and does not need to conform to the staff's program element guidance in GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," the staff noted that GALL AMP XI.M1 identifies that the 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda, is an acceptable ASME Code, Section XI edition for Inservice Inspection Programs that are credited for aging management of ASME Code Class components. Thus, the staff finds this update of the Inservice Inspection Program to be acceptable because it is in conformance with the "scope of program" program element in GALL AMP XI.M1.

In LRA Amendment 5, dated June 11, 2008, the applicant amended AMP B.1.18 to clarify that the applicable edition credited for aging management of ASME Code Class components at IP3 within the scope of the AMP is the 1989 Edition of the ASME Code, Section XI, with no addenda. Although the Inservice Inspection Program is a plant-specific AMP for the LRA and does not need to conform to the staff's program element guidance in GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," the staff noted that the staff's 1995 SOC on 10 CFR Part 54 identifies that ASME Code, Section XI editions up through the 2001 Edition of the ASME Code, Section XI, inclusive of the 2003 Addenda, are acceptable ASME Code, Section XI editions for Inservice Inspection Programs that are credited for aging management of ASME Code Class components. Thus, the staff finds the ASME Code, Section XI edition (i.e., the 1998 edition of the code) credited for IP3 is acceptable for aging management because it is in conformance with the staff's SOC position on 10 CFR Part 54 regarding the ASME Code, Section XI editions that are acceptable for aging management.

The staff verified that components within the scope of the program include the ASME Code Class 1, 2, and 3 components that are specified in Subsections IWB-1100, IWC-1100, IWD-1100, and the ASME Code Class 1, 2, and 3 component supports that are specified in AMSE Code Section XI Subsection IWF-1100. The staff verified that the components include all pressure-retaining components and their integral attachments. Based on this review the staff finds that the applicant's identification of components that are within the scope of the applicant's Inservice Inspection Program is acceptable because is in compliance with the applicable components that are mandated for inspection in the ASME Code, Section XI, Subsections IWB, IWC, IWD, and IWF, as endorsed for use through reference in 10 CFR 50.55a.

Entergy also stated that the ISI programs manage loss of material for piping and component supports, anchorages, and base plates by visual examination of components using NDE techniques, frequencies, and sample sizes specified in Subsection IWF examination categories. Twenty-five percent of Class 1 piping supports, 15 percent of Class 2 piping supports, 10 percent of Class 3 piping supports, and 100 percent of other supports are subject to VT-3 visual examination, as required by the Code. Entergy stated that the examination categories are in accordance with Table IWF-2500-1 and that for piping supports, the total percentage sample is comprised of supports from each system where the individual sample sizes are proportional to the total number of nonexempt supports of each type and function within each system. Thus, the staff concludes that the scope of the Entergy's ISI program for the component supports is acceptable because it includes the items identified in GALL AMP XI.S3, and because this provides an acceptable basis for meeting SRP-LR Section A.1.2.3.1 with respect to the scoping of components supports for the program.

Based on this review, the staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1 because: (1) the scope of the program includes the applicable ASME Code 1, 2, and 3 components that are mandated for inservice inspection in the 1989 Edition of the ASME Code, Section XI, Subsection IWB, IWC, IWD and IWF, and because this in compliance with the requirements of 10 CFR 50.55a and in conformance with the staff's SOC on 10 CFR Part 54, and (2) consistent with the recommendation in SRP-LR Section A.1.2.3.1, the

applicant identified the components that are with the scope of the AMP. The staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.18 states that the ISI Program is a condition monitoring program that does not include preventive actions.

For condition monitoring programs, SRP-LR Section A.1.2.3.2 states, "For condition or performance monitoring programs, they do not rely on preventive actions and thus, this information need not be provided."

The staff observed that the applicant's Inservice Inspection Program is characterized as a "condition monitoring" program that uses a combination of non-destructive and visual inspection methods to monitor for the effects of aging that are applicable to ASME Code Class 1, 2, and 3 components and their components supports. Based on its review, the staff concludes that the recommended guidance in SRP-LR Section A.1.2.3.2 is not applicable to the applicant's Inservice Inspection Program. Therefore, the applicant's "preventive actions" program element discussion for the Inservice Inspection Program is acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.18 states that "the program uses nondestructive examination (NDE) techniques to detect and characterize flaws. Volumetric examinations such as radiographic, ultrasonic or eddy current examinations are used to locate surface and subsurface flaws. Surface examinations, such as magnetic particle or dye penetrant testing, are used to locate surface flaws. Visual examinations detect cracks and symptoms of wear, corrosion, physical damage, evidence of leakage, and general mechanical and structural condition."

For condition monitoring programs, SRP-LR Section A.1.2.3.3 states, "[t]he parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s)," and "[f]or a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects. Some examples are measurements of wall thickness and detection and sizing of cracks."

The staff noted that Subsection IWA-2200 defines the ASME inspection methods that may be applied to ASME Code Class components and the parameters that these inspection methods are credited for. The staff also noted that IWA-2000 identifies that the various ASME inspection methods as a whole detect for aging effect parameters such as discontinuities or flaws (including cracking, pitting surface wastage, etc.), wear, corrosion, erosion, loss of integrity at bolted connections, and general mechanical and structural condition of the components. The staff also noted that the aging parameters discussed in IWA-2000 relate to the aging effects of loss of material, cracking, loss of preload, and reduction of fracture toughness in ASME Code Class components, The staff also noted that the aging effects identified in the applicant's "parameters monitored or inspected" program element were the same parameters as those identified and credited for in the ASME Code, Section XI, Subsection IWA-2200 paragraphs. Based on this review, the staff confirmed that the "parameters monitored or inspected" program element satisfies the guidance in SRP-LR Section A.1.2.3.3 because: (1) the parameters identified as being within the scope of the applicant's program are in

compliance with those identified in ASME Code, Section XI, Subsection IWA-2200, and (2) the aging parameters within the scope of the program relate back to either to the aging effects of loss of material, cracking, loss of preload, or reduction of fracture toughness in ASME Code Class components. Based on this review, the staff finds this program element acceptable.

(4) Detection of Aging Effects - LRA Section B.1.18 states that the ISI Program manages cracking on subcomponents of the reactor vessel, as applicable, for carbon steel, nickel alloy, carbon steel with stainless steel cladding, and stainless steel components, including bolting, using NDE techniques specified in ASME Section XI, Subsection IWB examination category.

The ISI Program manages loss of material due to wear on reactor vessel internal subcomponents, as applicable, for nickel alloy and stainless steel clevis inserts, radial keys, core alignment pins, and head/vessel alignment pins using NDE techniques specified in ASME Section XI, Subsections IWB examination categories.

The ISI Program manages cracking on reactor coolant system components, as applicable, for carbon steel, carbon steel with stainless steel cladding, stainless steel and cast austenitic stainless steel components, including bolting and support skirts, using NDE techniques specified in ASME Section XI, Subsections IWB examination categories. The Inservice Inspection Program also manages reduction of fracture toughness for valve bodies and pump casing made of cast austenitic stainless steel.

The ISI Program manages cracking on steam generator system components, as applicable, for carbon steel, carbon steel with stainless steel cladding, and stainless steel components, using NDE techniques specified in ASME Section XI, Subsections IWB examination categories.

The ISI Program manages loss of material for ASME Class MC and Classes 1, 2, and 3 piping and component supports and their anchorages and base plates by visual examination of components using NDE techniques specified in ASME Section XI, Subsection IWF examination categories.

No aging effects requiring management are identified for lubrite sliding supports. However, the ISI Program will confirm the absence of aging effects through the period of extended operation.

In the LRA, the applicant stated that the ISI Program will be revised to provide periodic inspections to confirm the absence of aging effects for lubrite sliding supports used in the steam generator and reactor coolant pump supports.

Both IP2 and IP3 have adopted risk-informed inservice inspection (RI-ISI) as an alternative to current ASME Section XI inspection requirements for Class 1, Category B-F and B-J welds pursuant to 10 CFR 50.55a(a)(3)(i). The RI-ISI was developed in accordance with the EPRI methodology contained in EPRI TR-112657, Revision B-A, "Revised Risk-Informed Inservice Inspection Evaluation Procedure." The risk informed inspection locations are identified as Category R-A.

For IP2, Article IWF of ASME Section XI, 2001 Edition and 2003 Addenda, does not contain any specific exemption criteria for component supports. For IP3, components exempt from examination are in accordance with the criteria contained in Code Case N-491-2, Alternate Rules for Examination of Classes 1, 2, 3 and MC Component Supports of Light-Water Cooled Power Plants, Section XI, Division 1, IWF-1230.

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.4.

The staff noted that the specific Examination Categories and Inspection Items in Table IWB-2500-1 establish the inspection methods, inspection frequencies, and flaw acceptance standards that are to be used on ASME Code Class 1 components and that Examination Categories and Inspection Items in Table IWF-2500-1 establish the inspection methods, inspection frequencies, and flaw acceptance standards that are to be used on ASME Code Class component supports. The staff noted that the applicant has credited the inspection requirements and inspection frequencies in applicable Table-IWB-2500-1 Examination Categories and Inspection Items for ASME Code Class 1 components and the inspection requirements, inspection frequencies, and sample sizes in applicable Table IWF-2500-1 Examination Categories and Inspection Items for ASME Code Class component supports. The staff finds this to be acceptable because it is in compliance with the requirements of 10 CFR 50.55a and the ASME Code, Section XI.

The staff noted that the LRA indicated that the applicant is crediting the inspection requirements and inspection frequencies in the applicable Table IWB-2500-1 Examination Categories and Inspection Items for the detection of aging effects in the steam generator (SG) secondary side shell, cone, and head components. The staff noted that, normally, the inspection requirements and inspection frequencies for the SG secondary side shell, cone, and head components would be performed in accordance with applicable requirements in the ASME Code, Section XI, Table IWC-2500-1 unless these components were designed to ASME Code Class 1 standards. The staff noted that the ASME Code, Section XI requirements in Subsection IWB are normally more stringent that those for ASME Code Class 2 and 3 requirements because the components are part of the reactor coolant pressure boundary. Thus, based on this review, the staff finds that using the inspection method and inspection frequency requirements for SG shell, cone, and head components is conservative because either the components were designed for ASME Code Class 1 standards and are inspecting in accordance with the applicable Examination Category and Inspection Items for these components in ASME Code, Section XI, Table IWB-2500-1 or that the components are ASME Code Class 2 or 3 components and use of the applicable Examination Category and Inspection Items for these components in ASME Code, Section XI, Table IWB-2500-1 is conservative relative to the requirements for inspection in Tables IWC-2500-1 or IWD-2500-1.

The staff noted that the AMRs in LRA Chapters 3.2, 3.3, and 3.4 did not credit the Inservice Inspection Program for aging management of the ESF components, auxiliary system (AUX) components, and steam and power conversion system (S&PC) components. Thus, the staff noted that the applicant was not crediting its implementation of the Examination Category requirements in ASME Code, Section XI,

Table IWC-2500-1 for aging management of the ASME Code Class 2 components and the Examination Category requirements in ASME Code, Section XI, Table IWD-2500-1 for aging management of the ASME Code Class 3 components. The staff found this to be acceptable because the AMRs in Sections V, VII, and VII of the GALL Report, Volume 2 do not credit GALL AMP XI.M1, "ASME Code, Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," for aging management of any of the aging effects that are attributed to ESF, AUX, and S&PC components.

The staff noted that the applicant indicated that it plans to enhance the Inservice Inspection Program to provide for periodic visual inspections of lubrite sliding supports used in the SG supports and reactor coolant pump (RCP) supports in order to confirm the absence of aging effects. The staff noted that the applicant could only treat this as an enhancement of the program if the AMP were categorized as an AMP that is consistent with the program elements in GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and if the enhancement would make the "detection of aging effects" program element of the AMP consistent with the "detection of aging effects" program element criteria that are provided in GALL AMP XI.M1. Thus, the staff informed the applicant that the aging effects that are applicable to the lubrite SG and RCP supports would need to be identified during the staff's review of the LRA and that the applicant would need to establish and justify its selection of the inspection methods, inspections frequencies, sample sizes, and acceptance criteria that are applicable to these lubrite components, and the corrective actions that would implemented if these acceptance criteria are exceeded. This was identified as Open Item 3.0.3.3.4-1.

The applicant responded to RAI 3.0.3.3.4-1 in a letter dated January 27, 2009. In this letter, the applicant identified the lubrite sliding supports in the SGs and RCPs as ASME code class supports that are within the scope of the requirement in the ASME Code, Section XI, Article IWF. In this letter, the applicant identified loss of material by wear and locking of the lubrite sliding supports by abnormal surface roughness as applicable aging effects for the lubrite sliding supports. The applicant clarified that there have not been any recordable indications of wear or abnormal surface roughness in the lubrite sliding supports detected to date and that as a result of this, the inspections performed on the sliding lubrite supports will be VT-3 visual examinations in order to confirm that these conditions do not exist in the supports. The applicant clarified that the inspection frequency and sample size of these VT-3 visual examinations will be done in accordance with the requirements of the ASME Code, Section XI, Article IWF, and that if any wear or abnormal surface roughness is detected, the applicant will evaluate the recordable conditions against the acceptance criteria in ASME Code, Section XI paragraph IWF-3410(a). The applicant stated that corrective actions for the component supports would be initiated in accordance with the requirements of the applicant's 10 CFR Part 50, Appendix B quality assurance program.

The staff noted that these lubrite sliding supports are supports for the RCPs, which are ASME Code Class 1 pumps in the reactor coolant pressure boundary, and for the SGs, which are classified as ASME Code class vessels/heat exchangers that have both an ASME Code Class 1 reactor coolant pressure boundary side and either an ASME Code Class 2 or Class 3 non-reactor coolant pressure boundary side. The staff also noted that the inspection methods, frequency and sample size for these supports is mandated by

10 CFR 50.55a and by Inspection Item F1.40, "Supports Other Than Piping Supports," in the ASME Code, Section XI, Table IWF-2500-1, Examination Category F-A. The staff noted that this inspection item pertains to non-piping supports in ASME Code Class 1, 2, and 3 piping systems and in MC structures, and calls for a VT-3 examination of 100% of these supports once every 10-Year ISI interval. Based on these verifications, the staff finds that the applicant has provided an acceptable basis for inspecting these lubrite sliding supports because: (1) the applicant has indicated that it will inspect the supports using the applicable ISI requirements for the supports, (2) these inspections will be done in accordance with the requirements of Inspection Item F1.40, "Supports Other Than Piping Supports," in the ASME Code, Section XI, Table IWF-2500-1, Examination Category F-A, and (3) this is consistent with the "detection of aging effects" and "monitoring and trending" program elements in GALL AMP XI.S3, "ASME Section XI, Subsection IWF." The staff concludes that RAI 3.0.3.3.4-1 is resolved and Open Item 3.0.3.3.4-1 is closed with respect to the inspection methods, frequencies, and sample sizes that are credited for these lubrite sliding supports.

The staff noted that Subparagraph IWF-3410(a) of the ASME Code, Section XI provides the appropriate acceptance criteria for relevant conditions in ASME Code Class 1, 2, or 3 components supports, including (but not limited to) those that induce deformations, structural degradations, misalignments, or improper clearances of the supports (such as might be induced if wear were occurring in the components), or abnormal surface roughness (such as might be induced if scaling or corrosion products were to form on the components). Based on this verification, the staff finds that the applicant has provided an acceptable basis for evaluating any relevant indications in the lubrite sliding supports because: (1) the applicant will use the mandated acceptance criteria in Subparagraph IWF-3410(a) of the ASME Code, Section XI as its basis for evaluating any relevant conditions that might occur in these ASME Code Class lubrite sliding supports and (2) this is consistent with the "acceptance criteria" program element in GALL AMP XI.S3. The staff concludes that RAI 3.0.3.3.4-1 is resolved and Open Item 3.0.3.3.4-1 is closed with respect to the acceptance criteria that are credited for these lubrite sliding supports.

The staff noted the GALL AMP XI.S3 identifies that the applicant's 10 CFR Part 50, Appendix B quality assurance program is an acceptable basis for establishing the corrective actions for ASME Code Class component supports because the Quality Assurance program would ensure that the corrective actions would be implemented in accordance with applicable requirements in the ASME Code, Section XI, Subparagraph IWF-3122. Based on this verification, the staff finds that the applicant has provided acceptable corrective actions for the lubrite sliding supports because: (1) the applicant has specified that the corrective actions for these supports will be implemented in accordance with the applicant's 10 CFR Part 50, Appendix B program, and (2) this is consistent with the "corrective actions" program element in GALL AMP XI.S3. The staff concludes that RAI 3.0.3.3.4-1 is resolved and Open Item 3.0.3.3.4-1 is closed with respect to the corrective actions that are credited for these lubrite sliding supports.

In Audit Item 60, the staff asked the applicant to justify its basis for using risk-informed inservice inspection (RI-ISI) for Examination Category B-J and B-F piping welds and for applying and using NRC-approved Code Case N-532 during the period of extended

operation. In its response, dated December 18, 2007, Entergy amended the LRA to remove from the LRA sentences referencing these items. At the same time, Entergy stated that IP ISI programs would continue to be implemented in full compliance with the Code requirements during the period of license renewal. The staff verified the applicant updated its Code of Record for IP2 to the 2001 Edition of the ASME Code, Section XI through 2003 Addenda. For IP3, the Code of Record is the 1989 Edition of the ASME Code, Section XI with no Addenda. The staff finds this to be acceptable because the SOC on 10 CFR Part 54 clarifies that the 2001 Edition of the ASME Code through 2003 Addenda and the 1989 Edition of the ASME Code with no Addenda are acceptable editions of the ASME Code, Section XI to use for aging management.

Based on this review, the staff confirmed that the "detection of aging effects" program element satisfies the guidance in SRP-LR Section A.1.2.3.4 because the applicant is applying the inspection methods, inspection frequencies, and samples sizes in Table IWB-2500-1 for ASME Code Class 1 components and for SG secondary side shell, cone, and head components and in Table IWF-2500-1 for ASME Code Class components supports and because these methods meet the SRP-LR Section A.1.2.3.4 criteria for applicants to justify the inspection methods, inspection frequencies and sample sizes that they select for aging management. Based on this review, the staff finds this program element acceptable.

(5) Monitoring and Trending - LRA Section B.1.18 states that results are compared, as appropriate, to baseline data and other previous test results. Indications are evaluated in accordance with ASME Section XI. If the component is qualified as acceptable for continued service, the area containing the indication is reexamined during subsequent inspection periods. Examinations that reveal indications that exceed the acceptance standards are extended to include additional examinations in accordance with ASME Section XI.

Inservice Inspection results are recorded every operating cycle and provided to the NRC after each refueling outage via Owner's Activity Reports. These reports include scope of inspection and significant inspection results. They are prepared and submitted in accordance with NRC-accepted ASME Section XI Code Case N-532-1 as referenced in RG 1.147.

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.5.

The staff's bases for approving the applicant inspection frequencies and sample sizes used in the inspections of ASME Code Class components has been discussed and justified in the staff's evaluation of the "detection of aging effects" program element for this AMP.

The staff noted that the applicant indicated that indications are evaluated against stated standards in the ASME Code, Section XI, and if found acceptable for service, the areas containing the indications are re-inspected during the next scheduled outage. The staff noted that that Articles IWB-2000, IWC-2000, and IWD-2000 all include criteria for performing successive inspections on component indications that are found to be acceptable for continued service, and for expanding the sample size if the indications

exceed the applicable flaw standard used for analysis in the Code. Based on this review, the staff finds the applicant's "monitoring and trending" program element description for performing successive inspections and sample expansion to be acceptable because it is in compliance with the requirements in ASME Code, Section XI.

In terms of record retention and reporting of data requirements, the staff noted that the applicant stated that records are prepared and provided to the NRC in accordance with applicable Owner's Activity Reports. The staff also noted that the ASME Code, Section XI, Article IWA-6000 provides the requirements for recording of data and reporting this data to the NRC, including requirements for defining owner activities and responsibilities, completing of NIS-1 data record forms, preparation of summary reports, submittal of summary to the NRC authorities, retaining records, reproducing records (including digitization requirements and microfiche requirements), retention of construction record requirements, maintenance of ISI records, retention of repair/replacement and supplement evaluation records. Based on this review, the staff finds that the applicant's basis for the preparation, recording, and submittal of plant ISI data and data summaries is acceptable because it is in compliance with the staff's record retention and reporting requirements in ASME Code, Section XI, Article IWA-6000.

Based on this review, the staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5 because: (1) the applicant has demonstrated that it will continue to comply with the requirements in Article IWA-6000 for record preparation, record retention and data and record reporting requirements and in Articles IWB-2000, IWC-2000, and IWD-2000 for performing successive inspections and for sample expansion, and (2) because the applicant has satisfied the "monitoring and trending" program element in SRP-LR Section A.1.2.3.5 for performing successive inspections of relevant flaw indications, sample expansion, and for record preparation, record retention, and data reporting. Based on this review, the staff finds this program element acceptable.

(6) Acceptance Criteria - LRA Section B.1.18 states that a pre-service, or baseline, inspection of program components was performed prior to startup to assure freedom from defects greater than code-allowable. This baseline data also provides a basis for evaluating subsequent inservice inspection results. Since plant startup, additional inspection criteria for Classes 2 and 3 components have been imposed by 10 CFR 50.55a for which baseline and inservice data has also been obtained. Results of inservice inspections are compared, as appropriate, to baseline data, other previous test results, and acceptance criteria of the ASME Section XI, for evaluation of any evidence of degradation.

The ISI Program acceptance standards for flaw indications, repair procedures, system pressure tests and replacements for ASME Classes 1, 2, and 3 components and piping are defined in ASME Section XI subsections IWA, IWB, and IWC paragraphs 3000, 4000, 5000 and 7000, respectively. Acceptance standards for examination evaluations, repair procedures, inservice test requirements, and replacements for ASME Class 1 component and piping supports are defined in ASME Section XI paragraphs IWF-3000, IWF-4000, IWF-5000 and IWF-7000, respectively."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.6.

The staff noted that the applicant indicated that it is using the applicable "acceptance criteria" in the ASME Code, Section XI, Subsections IWB, IWC, and IWD as its bases for establishing the acceptance criteria for assessing relevant indications in ASME Code Class components and in Subsection IWF for ASME Code Class supports. The staff noted that the flaw acceptance standards in the ASME Code, Section XI are based on satisfying the design basis loading conditions that are applicable to ASME Code Class components. The staff finds this to be acceptable because: (1) it is in compliance with the "acceptance criteria" requirements in the ASME Code, Section XI for Code Class 1, 2, and 3 components and their components supports, (2) these flaw evaluation criteria are based on a standard of meeting design basis loading conditions, and (3) this is in conformance with the recommended criteria in SRP-LR Section A.1.2.3.6.

Based on this review, the staff confirmed that the "acceptance criteria" program element satisfies the guidance in SRP-LR Section A.1.2.3.6 because: (1) the applicant is using the applicable acceptance criteria in the ASME Code, Section XI for the IP2 and IP3 ASME Code Class 1, 2, and 3 components and their components supports, and (2) this satisfies the criterion in SRP-LR Section A.1.2.3.6 to provide for timely corrective action before loss of intended function under these CLB design loads. The staff finds this program element acceptable.

(7) Corrective Actions – LRA Section B.1.18 states that "[i]f a flaw is discovered during an ISI examination, an evaluation is conducted in accordance with articles IWA-3000 as appropriate. If flaws exceed acceptance standards, such flaws are removed or repaired, or the component is replaced prior to its return to service. For Class 1, 2, and 3, repair and replacement are in conformance with IWA-4000 and IWA-7000. Acceptance of flaws which exceed acceptance criteria may be accomplished through analytical evaluation without repair, removal or replacement of the flawed component if the evaluation meets the criteria specified in the applicable article of the code. Corrective actions for this program will be administered under the site QA program which meets requirements of 10 CFR Part 50, Appendix B."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.7.

As discussed in the evaluation of the "scope of program" program element for the Inservice Inspection Program, the staff verified that the applicant's ASME Section XI Code of Record for IP2 for the 4th 10-year ISI interval is the 2001 Edition of ASME Code, Section XI through 2003 Addenda, and for IP3 for the 3rd 10-year ISI interval is the 1989 Edition of ASME Code, Section XI with no Addenda. The staff's corrective actions for ASME Code Class 1, 2, and 3 components in these ASME Code, Section XI editions are defined and specified in General Article IWA-4000, and in the specific corrective action provisions in IWB-4000 for Class 1 components, IWC-4000 for ASME Code Class 2 components, and IWD-4000 for ASME Code Class 3 components. The staff verified that the specific corrective action in articles IWB-4000, IWC-4000, and IWD-4000, provides either specific corrective action criteria for a specific ASME Code Class component or refers back to general corrective action provisions for these components that are

contained in Article IWA-4000. The staff also verified that these corrective actions are mandated for these components in accordance with inservice inspection requirements in 10 CFR 50.55a.

The staff noted that the "corrective actions" program element for AMP B.1.18, Inservice Inspection Program, credits only the corrective actions in the ASME Code, Section XI, Articles IWA-4000 and IWA-7000 as the corrective action criteria for the program. The ASME Code, Section XI editions of record for IP are the 2001 Edition of the ASME Code, Section XI inclusive of the 2003 Addenda for IP2, and the 1989 Edition of the ASME Code, Section XI, with no addenda for IP3. The staff noted that Entergy did not credit component-specific corrective action criteria in ASME Section XI, Article IWB-4000/7000 for Class 1 components, Article IWC-4000/7000 for Class 2 components, Article IWD-4000/7000 Class 3 components, or Article IWF-4000/7000 for ASME Code Class component supports as being within the scope of the "corrective action" program element for this AMP. By letter dated December 30, 2008, the staff asked the applicant to clarify whether the content of the "corrective actions" program element was intended to mean that Entergy will implement the corrective action provisions in the ASME Code, Section XI, Subsections IWA, IWB, IWC, IWD, and IWF that are applicable to the component Code Class in the applicable ASME Code, Section XI edition of record. This was identified as Open Item 3.0.3.3.4-2.

The applicant responded to the staff's RAI in a letter dated January 27, 2009. In this letter the applicant clarified that the content of the "corrective actions" program element discussion for this AMP is intended to mean that the corrective actions for this AMP will be implemented in accordance with the corrective actions provisions that are appropriate for ASME Code Class 1, 2, 3 components in the ASME Code, Section XI, Articles IWA, IWB, IWC, and IWD and for ASME Code Class component supports in the ASME Code, Section XI, Article IWF.

The staff noted that the applicant's response cited the appropriate ASME Code, Section XI corrective action articles for ASME Code Class 1, 2, and 3 components and for ASME Code Class supports. The staff also noted that the applicant's 10 CFR Part 50, Appendix B, quality assurance program includes appropriate quality assurance activities to ensure that inspections and corrective actions for ASME Code Class 1, 2, and 3 components and component supports will be done in accordance with appropriate requirements in the ASME Code, Section XI, ASME Code Cases referenced for use in 10 CFR 50.55a and the latest revision of NRC Regulatory Guide 1.147, or through applicable relief requests that are requested and approved by the staff through the alternative ISI requirements process in 10 CFR 50.55a(a)(3). The staff finds the "corrective actions" program element for this AMP, as amended in the response to RAI 3.0.3.3.4-2, to be acceptable because: (1) the applicant has indicated that the corrective actions for the ASME Code Class 1, 2, and 3 components and component supports will be done in accordance with appropriate ASME Code, Section XI requirements, (2) the applicant's 10 CFR Part 50, Appendix B quality assurance program provides an acceptable basis to ensure that corrective actions for ASME Code Class 1, 2, and 3 components and component supports will be done in accordance with appropriate AMSE Code Section XI requirements, NRC-approved ASME Code Cases, or alternative program requirements approved in accordance with 10 CFR 50.55a, and (3) this is consistent with the "corrective actions" program element criteria for ASME Code

Class 1, 2, and 3 components in GALL AMP XI.M1 and for ASME Code Class component supports in GALL AMP XI.S3. The staff concludes that RAI 3.0.3.3.4-2 is resolved and Open Item 3.0.3.3.4-2 is closed with respect to the acceptability of the "corrective actions" program element for this AMP.

(10) Operating Experience - LRA Section B.1.18 states that:

> ISI examinations at IP2 and IP3 were conducted during 2004 and 2005. Results found to be outside of acceptable limits were either repaired, evaluated for acceptance as is, or replacement activities were initiated. Identification of degradation and performance of corrective action prior to loss of intended function are indications that the program is effective for managing aging effects.
>
> A self-assessment of the ISI program was completed in October 2004. Review of current scope for 2R16 (2004) and 3R13 (2005) verified that the proper inspection percentages had been planned for both outages. A follow-up assessment was held for IP2 in March 2006 to ensure that all inspection activities required to close out the third 10-year ISI interval were scheduled for 2R17 (2006). Confirmation of compliance to program requirements provides assurance that the program will remain effective for managing loss of material of components.
>
> QA surveillances in 2005 and 2006 revealed no issues or findings that could impact effectiveness of the program.

The staff reviewed the self-assessment and QA audit reports for the ISI program and confirmed that the QA audit documents indicated that the IP ISI program appropriately identified and took corrective measures on the inspection findings. The staff also noted that the QA audit documents indentified several deficiencies with the applicant's ISI Program and provided appropriate recommendations to correct them. The staff noted that the QA audit documents did not indicate any programmatic weaknesses that would impact the effectiveness of the ISI Program in accomplishing its intended objectives or functions.

In RAI RCS-2, the staff asked the applicant, in part, to clarify how it performed its condition report review for relevant operating experience related to implementation of this program. The applicant provided its response to RAI RCS-2 in a letter dated June 5, 2008. The staff's evaluation of the applicant's response is documented in SER Section 3.0.3.2.9.

The staff noted that the applicant's response to RAI RCS-2 indicated that the applicant had performed an extensive enough review to search for and locate reports or documentation that would provide evidence of age-related aging effects in the IP2 or IP3 ASME Code Class 1 components. Thus, based on the response to RAI RCS-2, as made relative to the Inservice Inspection Program, the staff concludes that the applicant has performed a sufficient review for relative operating experience (OE) that is relevant to the AMSE Code Class 1 components and to the SG secondary shell side components that are inspected and evaluated ASME Code Class 1 standards in ASME Code,

Section XI Article IWB. The staff verified that the program is not credited for aging management of the ESF, Auxiliary System, and S&PC System components. RAI RCS-2 is resolved with respect to the operating experience review performed by the applicant for the ASME Code Class 1 components and the SG secondary shell-side components.

In RAI RCS-1, as issued relative to the applicant's Inservice Inspection Program, the staff asked the applicant to provide relevant operating experience information or CRs on borated water leakage, Class 1 seal housing bolt cracking, steam generator (SG) tube indications, and RV closure head weld indications that the staff had determined were applicable to the application.

The applicant responded to RAI RCS-1 by letter dated June 5, 2008. In its response, the applicant clarified that relevant condition reports existed that demonstrated applicable age-related degradation events for the following ASME Code Class 1 components:

- Boric acid leakage events for control rod drive (CRDs), CRD mechanisms, resistance temperature devices, RV lower head BMI nozzles, and RV seal tables, penetrations, fittings, and thimble tubes.
- Seal housing bolt cracking events
- SG tube indications
- Upper RV closure head weld indications

The staff has evaluated the boric acid leakage OE relative to the "operating experience" program element of AMP B.1.5, Boric Acid Corrosion Prevention Program. The staff evaluation of the "operating experience" program element of the Boric Acid Corrosion Prevention Program is given in SER Section 3.0.3.1.1 and includes the staff's basis for concluding that the system walkdowns and bare metal visual examinations of the Boric Acid Corrosion Prevention Program, as implemented through the Inservice Inspection Program, bound this operating experience and are capable of managing boric acid leakage and potential loss of material in steel ASME Class 1 components as a result of boric acid induced corrosion and wastage.

The staff evaluated the OE related to SG tube indications relative to the "operating experience" program element of AMP B.1.35, Steam Generator Integrity Program. The staff evaluation of the "operating experience" program element of the Steam Generator Integrity Program is given in SER Section 3.0.3.2.14 and includes the staff's basis for concluding that the inservice inspections that are performed in accordance with the Steam Generator Integrity Program, as implemented through the Inservice Inspection Program, bound this operating experience and are capable of managing loss of material and cracking in SG tubes, tubesheets and support plates.

In regard to the OE related to cracking in the upper RV closure head welds, the applicant stated that a recordable indication was detected in the #2 meridional weld of the IP3 upper RV closure head as a result of an ISI volumetric examination that was performed on the weld during the 2005 refueling outage. The applicant stated that the indication was similar to the indication from the original pre-service inspection record for the weld, which indicated that the indication was not from cracking and was acceptable

for service. The applicant stated that the indication was recorded to allow for comparisons to be made during future inservice inspections of the components. The applicant also stated that the remaining five meridional welds in the head were examined but the inspections were negative for recordable indications. The monitoring and trending activities and acceptance criterion comparisons taken by the applicant to compare the inspection results of the #2 meridional weld to past pre-service inspection results and to expand the sample size to the remaining meridional welds in the IP3 head are in compliance with ASME Code, Section XI requirements and demonstrate that the applicant is taking appropriate measures to assess relevant recordable indications for acceptability. Based on this review, the staff finds that applicant has appropriately addressed the OE relative to the #2 meridional weld in the IP3 upper RV closure head and that the applicant's Inservice Inspection Program bounds this OE because the steps taken to evaluated the recordable indication and expand the sample size of inspections performed on the meridional welds of the IP3 upper RV closure head are in compliance with ASME Code, Section XI requirements.

The staff evaluated the OE related to seal housing bolt cracking relative to the "operating experience" program element of AMP B.1.2, Bolting Integrity Program. The staff evaluation of the "operating experience" program element of the Bolting Integrity Program is given in SER Section 3.0.3.2.2 and includes the staff's basis for concluding that the inservice inspections that are performed on these Class 1 bolting component, as performed in accordance with the Bolting Integrity Program and implemented through the Inservice Inspection Program, bound this operating experience and are capable, in part, of managing cracking in ASME Code Class 1, 2, and 3 bolting, including the Class 1 seal housing bolts.

Based on this review, and the discussions in the previous four paragraphs, the staff finds the applicant has accounted for the OE relative to Class 1 components discussed in RAI RCS-1 and that the inspections of the Boric Acid Corrosion Prevention Program, the Steam Generator Integrity Program, the Reactor Vessel Head Penetration Inspection Program, or Bolting Integrity Program are bounding for the operation experience on these components and are capable of managing the applicable aging effects that are within the scope of the CRs on the operating experience. RCS-1 is resolved relative to the relationship of this OE to the Inservice Inspection Program.

Based on this review, the staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.17 and A.3.1.17, the applicant provided the UFSAR supplement for the Inservice Inspection Program. The staff noted the UFSAR Supplement summary descriptions provided in LRA Sections A.2.1.17 and A.3.1.17 incorporated the recommended summary description criteria from the SRP-LR that the "program consists of periodic volumetric, surface, and/or visual examination of components and their supports for assessment, signs of degradation, and corrective actions." However, the staff noted that the applicant's summary description also incorporated the applicant's proposal to enhance the program for lubrite components, as provided in LRA Commitment 11, which references these UFSAR Supplement sections.

In response to RAI 3.0.3.3.4-1 and Open Item 3.0.3.3.4-1, dated January 27, 2009, the applicant clarified that the inspection criteria, acceptance criteria, and corrective action criteria for the RCP and SG lubrite sliding supports would be implemented in accordance with the ISI requirements for ASME Code Class non-piping component supports in the ASME Code, Section XI, Article IWF. Based on this clarification, the staff finds that the applicant has fulfilled Commitment No 11 on specifying the inspection methods, frequency, sample size, acceptance criteria and corrective actions for the lubrite component supports and that the UFSAR Supplement summary descriptions for the applicant's Inservice Inspection Program are acceptable because they clarify that the Inservice Inspection Program will be implemented in accordance with the requirements of the ASME Code, Section XI, and 10 CFR 50.55a. The staff concludes that the issues raised in RAI 3.0.3.3.4-1 concerning UFSAR Supplement Summary Sections A.2.1.17 and A.3.1.17 are resolved and Open Item 3.0.3.3.4-1 is closed.

The staff reviewed LRA Sections A.2.1.17 and A.3.1.17 and finds the UFSAR supplement contains an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Inservice Inspection Program, the staff concludes that the applicant has demonstrated that 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 UFSAR supplement for this program, and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.5 Nickel Alloy Inspection Program

Summary of Technical Information in the Application. LRA Section B.1.21 describes the existing Nickel Alloy Inspection Program as a plant-specific program.

The Nickel Alloy Inspection Program manages aging effects of Alloy 600 items and 82/182 welds in the reactor coolant system not addressed by the Reactor Vessel Head Penetration Inspection Program or the Steam Generator Integrity Program. The aging effect requiring management for nickel alloys exposed to borated water at an elevated temperature is PWSCC. The Nickel Alloy Inspection Program includes elements of the Inservice Inspection Program, which specifies the NDE techniques and acceptance criteria for evaluation of cracks, and of the Boric Acid Corrosion Control Program. The Water Chemistry Control - Primary and Secondary Program maintains primary water in accordance with EPRI guidelines to minimize potential crack initiation and growth. Indian Point will continue to implement commitments to (a) NRC orders, bulletins, and generic letters addressing nickel alloys and (b) staff-accepted industry guidelines.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.21 on the applicant's demonstration of the Nickel Alloy 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 for the period of extended operation.

The staff reviewed the Nickel Alloy Inspection Program against the staff's recommended program element criteria that are provided in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1. The staff focused its review on assessing how the plant-specific program elements

for the Nickel Alloy Inspection Program would ensure adequate aging management when compared to the recommended program element criteria that are given in SRP-LR Section A.1.2.3. Specifically, the staff reviewed the following seven program elements of the applicant's program: (1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," and (10) "operating experience."

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff evaluates the Nickel Alloy Inspection Program's "corrective actions," "confirmatory process" and "administrative controls" program elements as part of the staff's evaluation of the applicant's Quality Assurance Program. The staff's evaluation of the applicant's Quality Assurance Program is given in SER Section 3.0.4. The staff's evaluation of the remaining program elements are given in the paragraphs that follow:

(1) Scope of the Program - LRA Section B.1.21 states that the following reactor vessel and reactor coolant system pressure boundary items are within the scope of the Nickel Alloy Inspection Program:

- Reactor inlet and outlet nozzle safe end weld material
- Reactor bottom mounted instrumentation tubes
- Reactor core support lugs (pads)
- Reactor closure head vent safe ends and welds
- Reactor head vent and Reactor flange leakoff piping

SRP-LR Section A.1.2.3.1 states: "The specific program necessary for license renewal should be identified. The scope of the program should include the specific structures and components of which the program manages the aging."

GALL Report XI.M11, "Nickel-Alloy Nozzles and Penetrations," denotes that this AMP has been replaced in part by AMP 11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (PWRs only)," and that guidance for the aging management of other nickel-alloy nozzles and penetrations is provided in the AMR line items of GALL Report Chapter IV, as appropriate.

Guidance for the aging management of other nickel-alloy nozzles and penetrations is provided in the AMR line items of Chapter IV, "Reactor Vessel, Internals, and Reactor Coolant System," as appropriate in the GALL Report. The items applicable to nickel-alloy material in Westinghouse reactors are found within sections A2, "Reactor Vessel (Pressurized Water Reactor)," B2, "Reactor Vessel Internals (PWR) – Westinghouse," C2, "Reactor Coolant System and Connected Lines (Pressurized Water Reactor)," and D1, "Steam Generator (Recirculating)."

The staff verified that the materials in the IP pressurizer nozzles and welded joints are not fabricated from Alloy 82/182/600 materials. The staff also verified the reactor coolant system contained no additional nickel alloy welds from those identified above. The staff also noted there have been numerous RAIs based on the review of the AMRs associated with the nickel alloy components. The staff determined that satisfactory

resolution of RAI 3.1.2-1 is necessary for confirmation of the "scope of the program." This was identified as part of Open Item 3.1.2-1.

The applicant responded to RAI 3.1.2-1 in a letter dated January 27, 2009. In this response, the applicant clarified that the following ASME Code Class 1 reactor coolant pressure boundary components are fabricated from Alloy 600 base metal materials or Alloy 82 or 182 weld filler metals:

- CRDM housing tubes (i.e., the CRDM nozzles)
- CRDM housing-to-housing tube safe-end adapter full penetration welds
- CRDM housing tube-to-upper reactor vessel closure head (RVCH) partial penetration welds
- upper RVCH vent adapter
- upper RVCH vent adapter-to-heat vent full penetration weld
- reactor vessel (RV) bottom mounted instrumentation (BMI) nozzles
- RV BMI nozzle-to-nozzle safe-end welds

The staff noted that these components are ASME Code Class 1 pressure boundary components and welds that are within the scope of B.1.21, Nickel Alloy Inspection Program. Based on this clarification, the staff finds that the applicant has resolved the issues raised in RAI 3.1.2-1 concerning the "scope of program" element for this AMP. The staff concludes that RAI 3.1.2-1 is resolved and Open Item 3.1.2-1 is closed with respect to the applicant's identification of nickel alloy base metal and weld components that are within the scope of the Nickel Alloy Inspection Program.

The staff also verified that the augmented inspection basis for the nickel alloy CRDM housing tubes (i.e., CRDM penetration nozzles) and their nickel alloy partial penetration upper RVCH-to-housing tube welds are within the scope of the applicant's Reactor Vessel Head Penetration Inspection Program (LRA AMP B.1.31). The staff's evaluation of the ability of the Reactor Vessel Head Penetration Program to manage cracking in the CRDM housing tubes and their nickel alloy upper RVCH-to-housing tube welds is in SER Section 3.0.3.1.12.

Based on this review, the staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1. The staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.21 states that "[n]o actions are taken as part of this program to prevent aging effects or mitigate aging degradation. However, primary water chemistry is maintained in accordance with EPRI guidelines by the Water Chemistry Control – Primary and Secondary Program, which minimizes the potential for PWSCC."

For condition monitoring program, SRP-LR Section A.1.2.3.2 states: "For condition or performance monitoring programs, they do not rely on preventive actions and thus, this information need not be provided."

The staff found that the Nickel Alloy Inspection Program uses nondestructive and visual examination methods to monitor the aging of the nickel alloy components as required by the ISI program and as augmented by the recommendations of applicable bulletins, generic letters and NRC approved industry guidance.

Based on this review, the staff confirmed that the "preventive actions" program element satisfies the guidance in SRP-LR Section A.1.2.3.2. The staff finds this program element acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.21 states that "the Nickel Alloy Inspection Program detects degradation by using the examination and inspection requirements of ASME Section XI, augmented as appropriate by examinations in response to NRC Orders, Bulletins and Generic Letters, or to accepted industry guidelines. The parameters monitored are the presence and extent of cracking."

For condition monitoring programs, SRP-LR Section A.1.2.3.3 states:

"The parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s)," and "[f]or a condition monitoring program, the parameter monitored or inspected should detect the presence and extent of aging effects. Some examples are measurements of wall thickness and detection and sizing of cracks."

The staff notes that the Nickel Alloy Inspection Program uses the appropriate volumetric, surface and visual NDE techniques for detection of degradation of the components identified in the scope of the program as required by ASME Code and recommended by the applicable bulletins, generic letters and industry guidance.

Based on this review, the staff confirmed that the "parameters monitored or inspected" program element satisfies the guidance in SRP-LR Section A.1.2.3.3. The staff finds this program element acceptable.

(4) Detection of Aging Effects - LRA Section B.1.21 states that "the Nickel Alloy Inspection Program detects cracking due to PWSCC prior to loss of component intended function. Some of the nickel alloy locations receive volumetric, surface and visual examination in accordance with ASME Section XI, supplemented as appropriate for current industry PWSCC considerations. Items receiving volumetric, surface and visual examination are listed below.

- Reactor vessel nozzle-to-safe end dissimilar metal welds receive a visual inspection every other outage and examination by volumetric techniques at 10-year intervals per ASME Section XI, Examination Category B-F.
- Bottom mounted instrumentation nozzles receive a visual examination from the exterior of the vessel in accordance with ASME Section XI, Examination Category B-P.
- The core support pads and guide lugs receive a visual examination in accordance with ASME Section XI, Examination Category B-N-2.

- The head vent and reactor flange leakoff piping receive a visual examination.

The EPRI MRP in conjunction with the Westinghouse owners groups (WOG) is developing a strategic plan to manage and mitigate PWSCC of nickel based alloy items. The main goal of this program will be to provide short and long term guidance for inspection, evaluation, and management of nickel alloy material and weld metal locations in PWR primary systems. Guidance developed by the MRP and WOG will be used to identify critical locations for inspection and augment existing ISI inspections where appropriate."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.4.

The staff noted that specific techniques and frequencies for monitoring the nickel alloy components are prescribed by ASME Code, Section XI for those components examined in accordance with the ISI program. For the other items included in the scope of the Nickel Alloy Inspection program the methods and frequencies of examination are recommended in the applicable bulletins, generic letters and industry guidance.

Based on this review, the staff confirmed that the "detection of aging effects" program element satisfies the guidance in SRP-LR Section A.1.2.3.4. The staff finds this program element acceptable.

(5) Monitoring and Trending - LRA Section B.1.21 states that "Records of the inspection program, examination and test procedures, examination/test data, and corrective actions taken or recommended are maintained in accordance with the requirements of ASME Section XI, Subsection IWA."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.5.

The staff noted that ASME Section XI requires, "recording of examination and test results that provide a basis for evaluation and facilitate comparison with the results of subsequent examinations." ASME Section XI also requires, "retention of all inspection, examination, test, and repair/replacement activity records and flaw evaluation calculations for the service lifetime of the component or system." ASME Section XI additionally provides rules for "additional examinations" (i.e., sample expansion), when flaws or relevant conditions are found that exceed the applicable acceptance criteria, to assist in determination of an extent of condition and causal analysis.

Based on this review, the staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable.

(6) Acceptance Criteria - LRA Section B.1.21 states that "Acceptance criteria for the volumetric inspections of dissimilar metal welds will be in accordance with ASME Section XI, IWB-3514. The acceptance standards for visual examination are specified in MRP-139. Acceptance standards for visual inspection of the core support pads are given in IWB-3520. Acceptance criteria for identified external surface damage, such as

from borated water leaks, are given in ASME Section XI, IWA-5250. Should additional inspections (volumetric, surface or visual) of nickel-based alloy locations (weld and base metal) be identified based on industry operating experience, where acceptance standards are not included in ASME Section XI, acceptance standards will be developed using appropriate analytical techniques."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.6.

The staff noted that ASME Section XI, IWB-3000, contains acceptance criteria appropriate for the reactor coolant pressure boundary components examined in accordance with Section XI. Also, ASME Section XI, IWA-5250, was verified to contain acceptable steps for evaluation and corrective measures for sources of leakage identified by visual examinations for leakage.

Based on this review, the staff confirmed that the "acceptance criteria" program element satisfies the guidance in SRP-LR Section A.1.2.3.6. The staff finds this program element acceptable.

(10) Operating Experience - LRA Section B.1.21 states that:

> The Nickel Alloy Inspection Program incorporates proven monitoring techniques and acceptance criteria for detection of cracking in nickel alloy components prior to a loss of function. Reactor coolant pressure boundary inspections have found no indications of cracking of nickel alloy components. The program considers industry operating experience, responds to industry trends in inspection, evaluation, repair, and mitigation activities, and is structured to be compatible with corresponding programs across the industry. In response to NRC Bulletin 2003-02, there were bare-metal visual examinations of the lower head of the reactor vessel in the fall of 2004 for IP2 and in the spring of 2005 for IP3. Examination of the area adjacent to each bottom-mounted instrumentation penetration, including each Alloy 600 penetration, the nickel alloy weld pad, and the circumference around the annulus between the penetration and weld pad, detected no cracking.

The staff confirms that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.20 and A.3.1.20, the applicant provided the UFSAR supplement for the Nickel Alloy Inspection Program. The staff reviewed these sections and finds the UFSAR supplement information an adequate summary description of the program, as required by 10 CFR 54.21(d).

UFSAR Supplement A.2.1.41, "Reactor Vessel Internals Aging Management Activities," includes a commitment that the site will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these

programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.

By letter dated June 11, 2008, the applicant revised the statement in the UFSAR Supplement sections A.2.1.20 and A.3.1.20 to incorporate the response to RAI 3.0.3.3.5-2 and stated IP would comply with future applicable NRC Orders and implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines associated with nickel alloys. The staff finds this to be acceptable because it is consistent with the aging management review basis for non-upper RVCH nozzle nickel alloy components, as provided in Table IV.A2 of the GALL Report, Volume 2, and the criteria in SRP-LR Section 3.1.3.2.13.

Conclusion. On the basis of its review of the applicant's Nickel Alloy Inspection Program, the staff concludes that the applicant has demonstrated that 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 UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.6 Non-EQ Bolted Cable Connections Program

Summary of Technical Information in the Application. LRA Section B.1.22 describes the new Non-EQ Bolted Cable Connections Program as a plant-specific program. The applicant stated that this program provides for one-time inspections on a sample of connections to be completed prior to the period of extended operation. The factors considered for sample selection will be application (medium and low voltage defined as less than 35 kV), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selections will be documented. If an unacceptable condition or situation is detected in the selected sample, the corrective action program will evaluate the condition and determine appropriate corrective action. The applicant also stated that this program will ensure that electrical cable connections perform intended functions through the period of extended operation and will be implemented prior to it.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.22 on the applicant's demonstration of the Non-EQ Bolted Cable Connections Program to ensure 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.

The staff reviewed the Non-EQ Bolted Cable Connections Program against the AMP elements found in the GALL Report, in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements ((1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience").

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The

staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.22 states that non-EQ connections associated with cables in the scope of license renewal are part of this program. This program does not include the high voltage (greater than 35 kV) switchyard connections. In-scope connections are evaluated for applicability of this program. The criteria for including connections in the program are that the connection is a bolted connection that is not covered under the EQ program or an existing preventive maintenance program.

SRP-LR Appendix A.1.2.3.1 states that the program scope includes the specific structures and components of which the program manages the aging.

The staff confirmed that the specific commodity groups for which the program manages aging effects are identified (Non-EQ bolted cable connections associated with cables within the scope of license renewal), which satisfies the guidance in SRP-LR Appendix A.1.2.3.1. The staff also determined that the exclusion of high-voltage (>35 kV) switchyard connections, connections covered under EQ program and the existing PM program is acceptable. Switchyard connections are addressed in SER Section 3.6.2.2. EQ cable connections are covered under 10 CFR 50.49. Cable connections under a preventive maintenance program are periodically inspected. On this basis, the staff finds that the applicant's "scope of program" program element is acceptable.

(2) Preventive Actions - LRA Section B.1.22 states that this one-time inspection program is a condition monitoring program; therefore, no actions are taken as part of this program to prevent or mitigate aging degradation.

SRP-LR Appendix A.1.2.3.2 states that condition monitoring programs do not rely on preventive actions, and thus, preventive actions need not be provided.

The staff confirmed that the preventive actions program element satisfies the guidance in SRP-LR Appendix B.1.2.3.2. The staff finds it acceptable because this is a condition monitoring program and there is no need for preventive actions. On this basis, the staff finds the applicant's "preventive actions" program element is acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.22 states that this program will focus on the metallic parts of the cable connections. The one-time inspection verifies that loosening of bolted connections due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation is not an aging effect that requires a periodic aging management program.

SRP-LR Appendix A.1.2.3.3 states that the parameters to be monitored or inspected should be identified and linked to the degradation of the particular structure and component intended function(s). The parameter monitored or inspected should detect the presence and extent of aging effects.

The staff confirmed that the parameters monitored/inspected program element satisfies the guidance in Appendix A.1.2.3.3 of the SRP-LR. Loosening (or high resistance) of

bolted cable connections are the potential aging effects due to thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation. The design of bolted cable connections usually account for the above stressors. The one-time inspection is to confirm that these stressors are not an issue that requires a periodic AMP. On this basis, the staff finds that the applicant's "parameters monitored or inspected" program element is acceptable.

(4) Detection of Aging Effects - LRA Section B.1.22 states that a representative sample of electrical connections within the scope of license renewal and subject to aging management review will be inspected or tested prior to the period of extended operation to verify there are no aging effects requiring management during the period of extended operation. The applicant stated that factors considered for sample selection will be application (medium and low voltage), circuit loading (high loading), and location (high temperature, high humidity, vibration, etc.). The technical basis for the sample selected will be documented. Inspection methods may include thermography, contact resistance testing, or other appropriate methods including visual based on plant configuration and industry guidance. The applicant also stated that one-time inspection provides additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practices are effective.

SRP-LR Appendix A.1.2.3.4 states that detection of aging effects should occur before there is a loss of the structure and component intended function(s). The parameters to be monitored or inspected should be appropriate to ensure that the structure and component intended functions will be adequately maintained for license renewal under all CLB design conditions.

The GALL Report AMP XI.E6 states that testing may include thermography, contact resistance testing, and other appropriate testing methods. In AMP B.1.22, the applicant states that inspection methods may include thermography, contact resistance testing, or other appropriate methods including visual inspection based on plant configuration and industry guidance. The staff requested the applicant to explain how visual inspection alone, if used, can detect loosening of bolted connections (Audit Item 63). In a letter dated December 18, 2007, the applicant responded that visual inspection is an alternate technique to thermography or measuring connection resistance of bolted connections that are covered with heat shrink tape, sleeving, insulating boots, etc., where the only alternative to visual inspection is destructive examination. The applicant also stated that an example of where visual inspection may be used is motor connections, where the motor lead is connected to the field cable in a local junction box. Typically these connections are completely covered with field splices, so there is no method to perform connection resistance testing of the connection. The practice would be to not remove the junction box cover when the cable is energized, so thermography would not be an option to determine a loose connection. Another example of using visual inspection would be in remote switchgear panels where the entire connection to the bus is covered with tape or an insulating boot.

In a letter dated March 24, 2008, the applicant supplemented its response and stated that because of personal safety practices, the junction box cover would not be removed when the cable is energized, so thermography could only be performed with the junction

box in place, which may not provide accurate results. Contact resistance measurements would require the destructive examination of the connection. The applicant's policies for personnel safety for energized components at a potential greater than 600 V are to observe a restricted approach boundary, which would preclude the removal of a bolted cover from energized components at a potential of greater than 600 V. The applicant stated that numbers of bolted connections that are greater than 600 V are limited to large motor, transformer, or generator connections (less than 30 connections, which are 3 connections per phase for 10 motors) for both units and 5 remote motor control centers for both units.

On August 29, 2007, the staff issued proposed license renewal interim staff guidance LR-ISG-2007-02, "Changes to Generic Lesson Learned (GALL) Report Aging Management Program (AMP) XI.E6, 'Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements,'" for public comment. In this ISG, the staff proposed changes to GALL AMP XI.E6 to clarify and recommend a one-time inspection, on a representative sampling, to ensure that either aging of metallic cable connections is not occurring or an existing preventive maintenance program is effective, such that a periodic testing is not required. Based on public and stakeholder comments, the staff has determined that resistance measurement or thermography may be a preferred method for testing loose cable connections. However, if resistance measurement can not be performed with the insulation in place, and for reasons of personnel safety, energized equipment can not be accessed to perform thermography, then visual inspection is an acceptable alternate inspection method for cable connections covered with insulation materials. The staff has previously permitted visual inspections every 5 years for covered bus connections in GALL XI.E4, Metal Enclosed Bus. If the applicant chooses visual inspection as an alternate to thermography or resistance measurement of cable connections covered with insulating materials (heat sink tapes, sleeving, insulation boots etc.), it can not use a one-time inspection and must perform periodic visual inspections. Periodic visual inspection can effectively detect loosening of cable connections by inspecting insulation materials for discoloration, cracking, chipping, or surface contamination. Absence of insulation deterioration will ensure that cable connections will not be loose. The staff is finalizing its position in the final ISG to permit periodic visual inspections for cable connections covered with insulation.

In a letter dated August 14, 2008, the applicant stated that following a telephone conference call held on June 2, 2008, with the NRC, Entergy agreed that visual inspections would not be used for one-time inspections in the Indian Point Non-EQ Bolted Cable Connection Program and the applicant revised LRA Section B.1.22 as follows:

> B.1.22 Non-EQ Bolted Cable Connection Program, Detection of Aging Effects. A representative sample of electrical connections within the scope of license renewal and subjected to aging management review will be inspected or tested prior to the period of extended operation to verify there are no aging effects requiring management during the period of extended operation. The factors considered for sample selection will be application (medium and low voltage), circuit loading (high loading), location (high temperature, high humidity, vibration, etc.). The technical

basis for the sample selected will be documented. Inspection methods may include thermography, contact resistance testing, or other appropriate methods based on plant configuration and industry guidance. The one-time inspection provides additional confirmation to support industry operating experience that shows that electrical connections have not experienced a high degree of failures, and that existing installation and maintenance practice are effective.

The staff finds the applicant supplemental response acceptable because the applicant committed to inspect or test a representative sample of electrical connections using methods such as thermography, contact resistance testing, or other appropriate methods. Resistance measurement or thermography is a preferred method for testing loose cable connections. These test methods are consistent with those in the GALL Report AMP XI.E6. On this basis, the staff finds that the applicant's description of "parameters monitored or inspected" program element is acceptable.

(5) Monitoring and Trending - LRA Section B.1.22 states that trending actions are not included as part of this program because this is a one-time inspection program.

SRP-LR Appendix A.1.2.3.5 states that monitoring and trending activities should be described, and they should provide predictability of the extent of degradation and thus affect timely corrective or mitigative actions. This program element describes how the data collected are evaluated and may also include trending for a forward look. The parameter or indicator trended should be described.

The staff confirmed that absence of trending for testing is acceptable since the test is a one-time inspection and the ability of trending is limited by the available data. Furthermore, the staff did not see a need for such activities. On this basis, the staff finds the applicant's "monitoring and trending" program element is acceptable.

(6) Acceptance Criteria - LRA Section B.1.22 states that the acceptance criteria for each inspection / surveillance are defined by the specific type of inspection or test performed for the specific type of cable connections. Acceptance criteria ensure that the intended functions of the cable connections can be maintained consistent with the CLB.

SRP-LR Appendix A.1.2.3.6 states that the acceptance criteria of the program and its basis should be described. The acceptance criteria, against which the need for corrective actions will be evaluated, should ensure that the structure and component intended functions are maintained under all CLB design conditions during the period of extended operation.

The staff confirmed that this program element satisfies the guidance in Appendix A.1.2.3.6 of the SRP-LR. The staff finds it acceptable on the basis that acceptance criteria for inspection/surveillance are defined by the specific type of inspection or test performed for the specific type of connection. The specific type of test when implemented, and acceptance criteria will ensure that the license renewal intended functions of the cable connections will be maintained consistent with the current licensing basis.

(10) Operating Experience - LRA Section B.1.22 states that operating experience shows that loosening of connections and corrosion of connections could be a problem without proper installation and maintenance. The applicant stated that industry operating experience supports this one-time inspection program in lieu of a periodic testing program to verify whether installation and maintenance have been effective. The Non-EQ Bolted Cable Connections Program is new. The applicant will consider industry operating experience when implementing this program.

SRP-LR Appendix A.1.2.3.10 states that operating experience should provide objective evidence to support the conclusion that the effect of aging will be managed adequately so that the structure and component intended functions will be maintained during the period of extended operation.

The staff notes that only a limited number of cases related to failed connections due to aging have been identified and these operating experiences do not support a periodic inspection as currently recommended in GALL AMP XI.E6. On August 29, 2007, the staff issued proposed license renewal interim staff guidance LR-ISG-2007-02, Changes to Generic Lesson Learned (GALL) Report Aging Management Program (AMP) XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" for public comments. In this ISG, the staff proposed changes to GALL AMP XI.E6 to clarify and recommend a one-time inspection, on a representative sampling, to ensure that either aging of metallic cable connections is not occurring or an existing preventive maintenance program is effective, such that a periodic testing is not required. The staff agreed with the applicant's assessment of operating experience. The staff finds that the proposed one-time inspection program will ensure that either aging of metallic cable connections is not occurring or the existing preventive maintenance program is effective such that a periodic inspection program is not required. On this basis, the staff finds that the applicant's operating experience element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.21 and A.3.1.21, the applicant provided the UFSAR supplement for the Non-EQ Bolted Cable Connections Program. The staff reviewed these sections and finds the UFSAR supplement information an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Non-EQ Bolted Cable Connections Program, the staff concludes that the applicant has demonstrated that 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 UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.7 Periodic Surveillance and Preventive Maintenance Program

Summary of Technical Information in the Application. LRA Section B.1.29, as amended by letters dated December 18, 2007, August 14, 2008, January 27, 2009, June 12, 2009, and June 30, 2009, describes the existing Periodic Surveillance and Preventive Maintenance Program as a plant-specific program.

Periodic inspections and tests in the Periodic Surveillance and Preventive Maintenance Program manage aging effects not managed by other AMPs. The Periodic Surveillance and Preventive Maintenance Program enhancements add new activities to the plant's preventive maintenance and surveillance programs, which generally implement preventive maintenance and surveillance testing activities through repetitive tasks or routine monitoring of plant operations. Visual and other NDE techniques inspect the following systems and structures:

- reactor building
- safety injection system
- main steam system
- circulating water system
- city water system
- condensate system
- river water system
- fresh water cooling system
- wash water system
- chemical and volume control system
- plant drains
- station air system
- instrument air system
- heating, ventilation, and air conditioning (HVAC) systems
- emergency diesel generators
- security generator system
- IP2 SBO/Appendix R diesel generator
- fuel oil system
- IP3 Appendix R diesel generator
- auxiliary feedwater
- containment cooling and filtration
- control room HVAC
- nonsafety-related systems affecting IP2 safety-related systems
- nonsafety-related systems affecting IP3 safety-related systems

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.29 on 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 for the period of extended operation.

The staff reviewed the Periodic Surveillance and Preventive Maintenance Program against the AMP elements found in the GALL Report, in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements ((1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience").

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The

staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.29 states that the "IPEC Periodic Surveillance and Preventive Maintenance Program, with regard to license renewal, includes those tasks credited with managing aging effects identified in aging management reviews."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.1.

The staff noted that the applicant had identified this AMP as a plant-specific AMP that does not have a GALL Report counterpart. The staff also noted that, of the aging management activities mentioned in the program description, the applicant had identified that the applicant had identified that the majority of the activities were new, and that for these activities, the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements for the AMP are enhanced as follows:

"Program activity guidance documents will be developed or revised as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation."

The applicant included this enhancement in Commitment 21 (refer to the letter of March 24, 2008). Because the Periodic Surveillance and Preventive Maintenance Program is a plant-specific AMP, the program activities for the components within the scope of the AMP should be defined in the program element discussions that are provided in the LRA for the AMP.

The staff noted that the "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program did not specify which components were within the scope of the program, although it did appear that the applicant had provided this type of information in the program description for the AMP. Thus, the staff was of the opinion that the applicant's "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program did not conform to the staff's general recommendation in SRP-LR Section A.1.2.3.1 because the applicant did not define the components that are within the scope of the program in its "scope of program" program element for the AMP. In RAI 3.0.3.3.7-1, Part 1, the staff informed the applicant that it would need to define the components and systems that are within the scope of the Periodic Surveillance and Preventive Maintenance Program. This was identified as Open Item 3.0.3.3.7-1, Part 1.

The applicant responded to RAI 3.0.3.3.7-1, Part 1 in a letter dated January 27, 2009. In this letter the applicant clarified that the components and systems within the scope of the "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program are those components and systems that have been identified in the program description for the AMP. The staff verified that the components and systems within the scope of the Periodic Surveillance and Preventive Maintenance Program are identified in the program description for the AMP, as amended by

applicable system and component scoping information for this AMP that was provided by the applicant in letters dated December 18, 2007, and August 14, 2008.

The staff noted that in the applicant's letter dated December 18, 2007, the applicant amended the "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program to add the main steam safety valve tailpipes in the main steam system and the atmospheric dump valve silencers to the scope of the Periodic Surveillance and Preventive Maintenance Program.

The staff also noted that in the applicant's letter dated August 14, 2008, the applicant amended the "scope of program" program element for the Periodic Surveillance and Preventive Maintenance Program to add the IP2 138 kV underground transmission cable for the offsite power feeder to the scope of the Periodic Surveillance and Preventive Maintenance Program.

The staff confirmed that information provided by the applicant in LRA Section B.1.29, as amended in its letters dated December 18, 2007, August 14, 2008, January 27, 2009, June 12, 2009, and June 30, 2009, clarified that the following systems and components are within the scope of the Periodic Surveillance and Preventive Maintenance Program:

- reactor building: reactor building cranes (polar and manipulator), crane rails, and girders, and refueling platform
- safety injection (SI) system: recirculation pump motor cooling coils and housing
- city water system: piping, piping elements and piping components
- chemical and volume control system (CVCS): charging pump casings
- plant drains: piping, piping components, and piping elements in the drains, and for IP2, the backwater valves
- station air system: station air containment penetration piping
- heating, ventilation and air conditioning (HVAC) systems: HVAC duct flexible connections, stored portable blowers, and flexible trunks
- emergency diesel generator (EDG) systems: EDG exhaust gas piping, piping components and piping elements; EDG duct flexible connections; EDG air intake and aftercooler piping, piping components and piping elements; EDG air start piping, piping components and piping elements; and EDG cooling water makeup supply valves
- security generator system: security generator exhaust piping, piping components and piping elements; and security generator radiator tubes
- IP2 station blackout/fire protection diesel generator (SBO/Appendix R DG): SBO/Appendix R DG exhaust gas piping, piping components, and piping elements; SBO/Appendix R diesel engine turbocharger and aftercooler housing, including external surfaces of the tubes and fins; and SBO/Appendix R jacket water heat exchanger bonnet and tubes
- IP3 fire protection diesel generator (Appendix R DG): Appendix R DG exhaust gas piping, piping components, and piping elements; Appendix R DG radiator;

Appendix R DG aftercooler; Appendix R starting air piping, piping components, and piping elements; and Appendix R DG crankcase exhaust subsystem piping, piping components and piping elements

- fuel oil system: SBO/Appendix R diesel fuel oil cooler, and the diesel fuel oil trailer transfer tank and associated valves
- auxiliary feedwater system: piping, piping components, and piping elements
- containment cooling and filtration system: containment cooling duct flexible connections; and containment cooling fan units, including damper housings, filter housings, moisture separators, and heat exchanger headers, housings, and tubes
- control room HVAC: condensers and evaporators; control room HVAC ducts and drip pans; and duct flexible connections
- IP2 non-safety system affecting safety systems (NSAS): piping, piping components, and piping elements in the circulating water system (including flexible elastomer piping), city water system, intake structure, EDG system, fresh water cooling water system, instrument air system, integrated liquid waste handling system, lube oil system, radiation monitoring system, river water service system, station air system, waste disposal system, wash water system, water treatment plant, and other miscellaneous NSAS piping systems
- IP3 NSAS: piping, piping components, and piping elements in the chlorination system, circulating water system (including flexible elastomer piping), EDG system, floor drain system, gaseous waste disposal system, instrument air system, liquid waste disposal system, nuclear equipment drain system, river water system, station air system, steam generator sampling system, and secondary plant sampling system
- IP2 and IP3 pressurizer relief tanks
- main steam safety valve tailpipes
- atmospheric dump valve silencers
- IP2 138 kV underground transmission cable for the offsite power feeder
- main condenser tube internal surfaces
- instrument air aftercooler tube internal surfaces
- fresh water/river water heat exchanger internal and external surfaces

Based on this verification, the staff finds that the applicant's "scope of program" element, as amended in the applicant's letter of December 18, 2007, August 14, 2008, January 27, 2009, June 12, 2009, and June 30, 2009, is acceptable because: (1) the amended basis clarifies which plant systems and components at IP2 and IP3 are within the scope of the Periodic Surveillance and Preventive Maintenance Program, and (2) the systems and components listed in the amended basis conform to the recommendation in SRP-LR Section A.1.2.3.1 that systems and components within the scope of an AMP should be identified in the "scope of program" program element for the AMP.

The staff concludes that RAI 3.0.3.3.7-1, Part 1 is resolved and Open Item 3.0.3.3.7-1, Part 1 is closed with respect to identifying the systems and components that are within the scope of the Periodic Surveillance and Preventive Maintenance Program.

Based on this review, the staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1.

(2) Preventive Actions - LRA Section B.1.29 states that "inspection and testing activities used to identify component aging effects do not prevent aging effects. However, activities are intended to prevent failures of components that might be caused by aging effects."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.2.

The staff noted that the applicant has identified the Periodic Surveillance and Preventive Maintenance Program as a both an existing condition monitoring program and an existing performance monitoring program, and that the program does not include any aging management activities to prevent or mitigate the effects of aging that are applicable to the components within the scope of the AMP. Based on this review, the staff concludes that the applicant has provided an acceptable basis for concluding that the criterion in SRP-LR A.1.2.3.2 is not applicable to the Periodic Surveillance and Preventive Maintenance Program because the program is not a preventive or mitigative-based AMP and does not include any activities that are designed to prevent or mitigate the effects of aging.

The staff confirms that the "preventive actions" program element satisfies the guidance in SRP-LR Section A.1.2.3.2.

(3) Parameters Monitored or Inspected - LRA Section B.1.29 states that this program "provides instructions for monitoring structures, systems, and components to detect degradation. Inspection and testing activities monitor various parameters including system temperatures, wall thickness, surface condition, and signs of cracking."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.3.

The staff noted that SRP-LR Section A.1.2.3.3 recommends that "parameters monitored or inspected" program element for AMPs is made to accomplish two objectives: (1) identify the aging effect(s) (degradation types) that the program manages, and (2) provide a link between the parameters that the program monitors for and the aging effect(s) the program is credited to manage. The staff noted that in the "parameters monitored or inspected" program element for the AMP, the applicant only mentioned "system temperatures, wall thickness, surface condition, and signs of cracking" as examples of the parameters that the program monitors for. The staff noted that, in the program description for the AMP, the applicant listed the following four (4) aging effects that the program monitors for: (1) cracking, (2) loss of material, (3) fouling, and (4) changes in material properties for elastomeric or polymeric (including rubber)

materials. The staff noted, however, that, with the exception of cracking, the applicant did not identify the aging effects that are within the scope of the AMP and that AMP monitors or inspects for and that the applicant also did not specifically identify and link the specific parameters that the program monitors or inspects for to each of the aging effects that are within the scope of the program.

To address these issues, the staff issued RAI 3.0.3.3.7-1, Part 2. In this RAI, the staff asked to applicant to clarify which aging effects are managed by the Periodic Surveillance and Preventive Maintenance Program, which parameters are indicative of these aging effects and would be monitored for as part of the applicant's implementation of the program, and which inspection techniques would be used to detect the parameters that are indicative of the applicable aging effects. This was identified as Open Item 3.0.3.3.7-1, Part 2.

By letter dated January 27, 2009, the applicant responded to RAI 3.0.3.3.7-1, Part 2. In this letter, the applicant included an aging effect monitoring table that: (1) identifies the particular aging effects that are managed by the Periodic Surveillance and Preventive Maintenance Program, (2) provides the aging mechanisms that could induce each of particular aging effects requiring management under the program, (3) provides the parameters that would be indicative of the particular aging effects that will be managed and monitored for under the AMP, and (4) provides the inspection techniques that would be used to detect the parameters that the applicant is monitoring for.

The table below summarizes the information provided in the applicant's aging effect monitoring table.

Parameters Monitored and Inspection Methods for Specific Aging Effects and Mechanisms			
Aging Effect	By Aging Mechanism	Parameter Monitored	Inspection Method
Loss of Material	Crevice Corrosion	Surface condition or wall thickness	Visual (VT-1 or equivalent) or or Volumetric (RT or UT)
	Galvanic Corrosion	Surface condition or wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
	General Corrosion	Surface condition or wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
	Microbiologically Influenced Corrosion (MIC)	Surface condition or wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
	Pitting Corrosion	Surface condition or wall thickness	Visual (VT-1 or equivalent) or Volumetric (RT or UT)
	Erosion	Surface condition or wall thickness	Visual (VT-3 or equivalent) or Volumetric (RT or UT)
Cracking	SCC or cyclical loading	Cracks	Enhanced Visual (VT-1 or equivalent) or Volumetric (RT or UT)
Cracking in elastomeric components		Cracks	Visual (VT-3 or equivalent)

Parameters Monitored and Inspection Methods for Specific Aging Effects and Mechanisms			
Aging Effect	By Aging Mechanism	Parameter Monitored	Inspection Method
Changes in material properties of elastomeric components		Hardening or Cracks	Visual (VT-3 or equivalent)

The staff found the clarifications and information provided in the aging effect monitoring table were acceptable, with certain exceptions, because the information was in conformance with the similar aging-effect-parameter combinations recommended for aging management in GALL AMP XI.M32, "One-Time Inspection." The exceptions in the applicant's aging effect monitoring table that needed further clarification are discussed and evaluated below.

The staff noted that in the applicant's letter of December 18, 2007, the applicant identified fouling as an aging mechanism and monitoring parameter that could be used to provide indication of a loss of material or loss of heat transfer capability in heat exchanger tubes or cooling coil fins that are within the scope of this AMP. The identification of fouling as an aging mechanism which can lead to a loss of material or a loss of heat transfer capability is consistent with GALL Report Table IX.F. Because the applicant's position is consistent with the recommendation in the GALL Report, the staff finds this acceptable.

The staff also noted that the aging effect monitoring table in the applicant's response to RAI 3.0.3.3.7-1, Part 2, indicated that elastomeric flexible connections would be monitored to detect cracking. The staff finds this to be acceptable because cracks in solid materials are extrinsic thermodynamic properties that can be directly monitored by inspection. The applicant also clarified that monitoring of cracks and the hardness of elastomeric components would be monitored for indications of any changes that might occur in the material properties of the elastomers during the period of extended operation. The staff finds this to be acceptable because the presence of a crack in the elastomeric material may provide an indirect indication on whether the material is undergoing embrittlement or is losing its elastic properties over time. In addition, the monitoring of hardness by flexible manipulation of the materials will be capable of demonstrating whether the elastomeric materials are degrading. Thus, the staff concludes that the applicant has established an acceptable basis for the parameters that will be used to monitor for cracking and/or changes of the material properties of elastomeric components.

Based on its review, the staff confirmed that the "parameters monitored or inspected" program element satisfies the recommendations in the GALL Report and the guidance in SRP-LR Section A.1.2.3.3. The staff concludes that RAI 3.0.3.3.7-1, Part 2 is resolved, and Open Item 3.0.3.3.7-1, Part 2 with respect to the acceptability of the "parameters monitoring or inspected" program element for this AMP is closed.

(4) Detection of Aging Effects - LRA Section B.1.29 states that:

> Preventive maintenance activities provide for inspections to detect aging effects. Periodic surveillances provide for testing to detect aging effects. Inspection and testing intervals are established such that they provide timely detection of degradation. Inspection and testing intervals are dependent on component material and environment and take into consideration industry and plant-specific operating experience and manufacturers' recommendations. Each inspection or test occurs at least once every five years with the exception of the following.
>
> - Components associated with emergency and Appendix R diesel generators are inspected every six years in accordance with manufacturer recommendations.
> - Appendix R diesel generator crankcase exhauster inspection is every ten years in accordance with manufacturer recommendations.
> - Copper alloy components exposed to city water are inspected every ten years since city water is treated per New York State requirements and aging effects are not expected.
> - The internals of each pressurizer relief tank are inspected every ten years since the tank is coated.
>
> The extent and schedule of inspections and testing assure detection of component degradation prior to loss of intended functions. Established techniques such as visual inspections or NDE are used. In cases where a representative sample is inspected by this program, the sample size will be based on Chapter 4 of EPRI document 107514, Age Related Degradation Inspection Method and Demonstration, which outlines a method to determine the number of inspections required for 90 percent confidence that 90 percent of the population does not experience degradation (90/90). Each group of components with the same material-environment combination is considered a separate population. The program provides for increasing inspection sample size in the event that aging effects are detected. Unacceptable inspection findings are evaluated in accordance with the IPNG corrective action process to determine the need for accelerated inspection frequency and for monitoring and trending the results.

The staff compared this program element against the criteria in SRP-LR Section A.1.2.3.4.

The staff noted that the applicant's "detection of aging effects" program element did identify that either visual examinations or NDE would be performed on the specific

system components that are within the scope of the AMP at any inspection interval of at least once every five years with the following exceptions:

- Appendix R fire protection diesel generators: passive components inspected at least once every 6 years in accordance with manufacturer recommendations, with the exception of the crank case exhaust piping components once every 10 years in accordance with manufacture recommendations.
- Copper components exposed to city water once every 10 years
- Pressurizer relief tank internal surfaces once every 10 years

The staff also noted that the applicant appeared to be crediting visual examinations, in part, to manage cracking but did not specify that the visual techniques would be VT-1, enhanced VT-1, VT-2 or VT-3 techniques. The ASME Code, Section XI, an NRC endorsed document in 10 CFR 50.55a, indicates that only volumetric inspection techniques (such as UT or RT) are capable of detecting a crack throughout the volume of a component and that only VT-1 or enhanced VT-1 visual examination techniques or surface examination techniques (such as PT or MT) are capable of detecting surface penetrating cracks. Thus, the staff needed additional information on the inspection techniques that would be credited under this AMP to detect cracking in the components that are within the scope of the Periodic Surveillance and Preventive Maintenance Program and for which cracking is identified as an applicable aging effect requiring management.

The staff noted that, for the majority of the elastomeric or polymeric components within the scope of the AMP, the applicant credited both visual examinations and manual flexing of the components to manage changes in material properties of these elastomeric or polymeric components. The staff noted that material properties are intrinsic thermodynamic properties that cannot be monitored by direct visual or NDE inspection methods, and that changes in material properties (such as loss of fracture toughness, hardening, or increases or reductions in strength) are more appropriately managed through appropriate material property analyses (including destructive analyses) or though performance of physical tests (such as flexing, etc.) that could provide some indication of whether the material properties for the components were changing. Thus, the staff sought clarification on: (1) how a visual examination method would be capable of indicating a change in the material properties of the elastomeric or polymeric components that are within the scope of the AMP, and (2) why flexing had not been credited for managing changes in these material properties for the flexible trunks used in the circulating water system and in the elastomeric flexible connections that are located in the intake portion of the EDG duct.

To address these issues, the staff issued RAI 3.0.3.3.7-1, Part 2. In this RAI, the staff asked the applicant to clarify which aging effects are managed by the Periodic Surveillance and Preventive Maintenance Program, which parameters are indicative of these aging effects and would be monitored as part of the applicant's implementation of the program, and which inspection techniques would be used to detect the parameters that are indicative of the applicable aging effects. This was identified as Open Item 3.0.3.3.7-1, Part 2.

The applicant responded to RAI 3.0.3.3.7-1, Part 2, in a letter dated January 27, 2009. In this letter, in order to demonstrate conformance with the recommendations for "parameters monitored or inspected" program elements in SRP-LR Section A.1.2.3.3, the applicant included an aging effect monitoring table that: (1) identifies the particular aging effects that are managed by the Periodic Surveillance and Preventive Maintenance Program, (2) provides the aging mechanisms that could induce each of particular aging effects requiring management under the program, (3) provides the parameters that would be indicative of the particular aging effects that will be managed and monitored for under the AMP, and (4) provides the inspection techniques that would be used to detect the parameters that the applicant is monitoring. The table above summarizes the information provided in the applicant's aging effect monitoring table. The staff noted that in the applicant's aging effect monitoring table, it identified that the following inspection techniques would be used as condition monitoring methods for this AMP.

(1) VT-3 or equivalent visual techniques, or UT or radiographic techniques (i.e., volumetric methods), will be used to manage loss of material due to general corrosion, galvanic corrosion, MIC, or erosion. The staff finds this to be acceptable because: (1) AMSE Code Section XI, paragraph IWA-2213 lists VT-3 visual examination methods as acceptable method for detecting surface discontinuities or imperfections that may result from mechanisms such as corrosion or erosion, and (2) ASME Code, Section XI, paragraphs IWA-2231 and IWA-2232 list UT and RT methods as acceptable volumetric inspection methods that are capable of detecting any discontinuities that may occur throughout the material and thickness of a component.

(2) VT-1 or equivalent visual techniques, or UT or radiographic techniques (i.e., volumetric methods), will be used to manage loss of material by pitting corrosion or crevice corrosion. The staff finds this to be acceptable because: (1) AMSE Code Section XI, paragraph IWA-2213 list VT-1 visual examination methods as acceptable visual examination techniques for detecting surface discontinuities or imperfections cracks, wear, corrosion or erosion, and (2) ASME Code, Section XI, paragraphs IWA-2231 and IWA-2232 list UT and RT methods as acceptable volumetric inspection methods that are capable of detecting any discontinuities that may occur throughout the material and thickness of a component,

(3) VT-1 or equivalent visual techniques, or volumetric methods (e.g., UT or RT), will be used to manage cracking in metallic components. The staff finds this to be acceptable because: (1) AMSE Code Section XI, paragraph IWA-2213 lists VT-1 visual examination methods as acceptable visual examination techniques for detecting surface discontinuities or imperfections, cracks, wear, corrosion or erosion and (2) ASME Code, Section XI, paragraphs IWA-2231 and IWA-2232 list UT and RT methods as acceptable volumetric inspection methods that are capable of detecting any discontinuities that may occur throughout the material and thickness of a component,

(4) VT-3 or equivalent visual techniques, coupled with physical manipulations, will be used to manage cracking in elastomer components. The staff finds this to be acceptable because flexing of the components will capable of distorting (opening

up) surfaces such that surface breaking cracks in the materials will be capable of being detected as a surface discontinuity, and because the flexible manipulations will be capable of determining whether the elastomeric materials are losing their elastic properties or are hardening or embrittling over time.

Based on this review, the staff finds that the applicant's "detection of aging effects" program element, as supplemented with information in the applicant's letter of January 27, 2009, is acceptable because the applicant has proposed valid inspection or functional testing to manage the effects of aging for the components within the scope of this AMP. Additionally, the applicant's program element meets the recommendation in SRP-LR Section A.1.2.3.4 to identify the methods that will be used to monitor the effects of aging and the parameters that are indicative of the aging effects.

The staff concludes that RAI 3.0.3.3.7-1, Part 2 is resolved and Open Item 3.0.3.3.7-1, Part 2 is closed with respect to identify the inspection methods that will be used to monitor for the effects of aging under this AMP.

(5) Monitoring and Trending - LRA Section B.1.29 states that "preventive maintenance and surveillance testing activities provide for monitoring and trending of aging degradation."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.5.

The staff noted that the applicant's "monitoring and trending" program element discussion for the Periodic Surveillance and Preventive Maintenance Program only mentioned that the activities within the scope of the AMP provided for adequate monitoring and trending. The staff noted that the "monitoring and trending" program element for the AMP did not provide any discussion on how the data from the inspections performed under the "detection of aging effects" program element would be collected, quantified, or evaluated against applicable acceptance criteria, and used to make predictions related to degradation growth or to schedule re-inspections of the components. Thus, the staff determined that the "monitoring and trending" program element for the Periodic Surveillance and Preventive Maintenance Program would need to be amended to specify how the data from the inspections performed under the "detection of aging effects" program element would be collected, quantified, or evaluated against applicable acceptance criteria, and used to make predictions related to degradation growth or to schedule re-inspections of the components.

To address these issues, the staff issued RAI 3.0.3.3.7-1, Part 3. In this RAI, the staff asked the applicant to clarify how the inspection results and flexible manipulation data for this AMP would be collected and quantified, or evaluated against appropriate acceptance criteria, and how the trending results would be used to make predictions relative to degradation growth or to schedule re-inspections or repairs of the components that are managed by this AMP. This was identified as Open Item 3.0.3.3.7-1, Part 3.

The applicant responded to RAI 3.0.3.3.7.1-1, Part 3 in a letter dated January 27, 2009. In this response, the applicant stated that the initial periodicity of inspections and manual flexing is based on vendor recommendations, industry guidance, input from other

Entergy nuclear sites, and IP specific operating experience, and that the results of these inspections and manual flexing are collected as part of the work control process. The applicant also clarified that any indications or relevant conditions of degradation are reported and submitted for evaluation under the corrective action program and that the evaluation is performed against criteria which ensure that the structure or component intended function(s) are maintained under all current licensing basis design conditions during the period of extended operation. The applicant stated that the results of these inspections and manual flexing are trended by an assigned "responsible engineer," and that, if a potential need for a change in scope or frequency of inspections is indicated based on identified patterns of degradation, a preventive maintenance change request is processed. The staff finds this to be acceptable because it is in conformance with the quality assurance requirements in the applicant's quality assurance program for monitoring of conditions adverse to quality and for taking appropriate corrective actions for conditions that are unacceptable for further service.

Based on this response, the staff finds that the applicant's "monitoring and trending" program element, as supplemented with the information in the applicant's response to RAI 3.0.3.3.7-1, Part 3, is acceptable because the applicant has clarified how the inspection results and results of physical manipulation flexing tests for elastomeric components will be collected and trended consistent with the recommendations in SRP-LR Section A.1.2.3.5.

The staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable. RAI 3.0.3.3.7-1, Part 3 is resolved and Open Item 3.0.3.3.7-1, Part 3 is closed.

(6) Acceptance Criteria - LRA Section B.1.29 states that the "Periodic Surveillance and Preventive Maintenance Program acceptance criteria are defined in specific inspection and testing procedures. Acceptance criteria include appropriate temperature, no significant wear, corrosion, cracking, change in material properties (for elastomers), and significant fouling based on applicable intended functions established by plant design basis."

The staff reviewed this program element against the criteria in SRP-LR Section A.1.2.3.6.

The staff noted that the applicant's "acceptance criteria" program element for the Periodic Surveillance and Preventive Maintenance Program only made a general statement as to what the acceptance criteria are and did not establish specific acceptance criteria for each of the aging effects that are applicable to the components within the scope of the AMP. The staff also noted that the applicant had indicated that the "acceptance criteria" program element would be enhanced, in part, to specific what these acceptance criteria are. The staff sought clarification as to why establishment of the acceptance criteria for this AMP could be deferred through the applicant's enhancement of the program, as stated in LRA Commitment No. 21. Therefore, in RAI 3.0.3.3.7-1, Part 4, the staff asked the applicant to define what the acceptance criteria are for each of the aging effects that are managed under the scope of the AMP. This was identified as Open Item 3.0.3.3.7-4.

The applicant responded to RAI 3.0.3.3.7.1-1, Part 4 in a letter dated January 27, 2009. In this response, the applicant stated that any indications or relevant conditions of degradation are reported and submitted for further evaluation as part of the corrective action program and that these evaluations are performed against specific acceptance criteria which ensure that the structure or component intended function(s) will be maintained under all current licensing basis design conditions during the period of extended operation. The applicant clarified that these acceptance criteria include no unacceptable wear, corrosion, cracking, change in material properties (for elastomers), or significant fouling, and that the specific quantitative or qualitative criteria (i.e., limits) on acceptability are contained in manufacturer information or vendor manuals for some individual components. The applicant clarified that an engineering review process is used to establish the acceptance criteria for those situations where appropriate manufacturer data are unavailable. The staff noted that this is consistent with the following guidance in SRP-LR Section A.1.2.3.6:

"Acceptance criteria could be specific numerical values, or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria to ensure that the structure and component intended function(s) will be maintained under all CLB design conditions."

Based on its review, the staff finds that the applicant "acceptance criteria" program element, as supplemented by information in the applicant's response to RAI 3.0.3.3.7-1, Part 4, is acceptable because the applicant has clarified what the acceptance criteria are for the aging effects within the scope of this AMP.

The staff concludes that RAI 3.0.3.3.7-1, Part 4 is resolved and Open Item 3.0.3.3.7-1, Part 4 is closed.

(10) Operating Experience - LRA Section B.1.29, as amended by letter dated June 30, 2009, states that typical inspection results of this program include:

- IP2 reactor building polar crane (May 2006): no indication of corrosion, cracking, or wear in the crane structural members.
- IP3 reactor building polar crane (February 2001 and March 2005): no indication of corrosion, cracking, or wear in the crane structural members.
- IP2 and IP3 recirculation pumps and related system components (2005 and 2006): no deficiencies.
- IP2 diesel generator building floor drain backwater valves (October 2006): no loss of material.
- IP2 and IP3 EDGs (2005 and 2006): no unacceptable loss of material.
- Security generator (January 2002 and December 2005): no significant corrosion or wear.
- IP3 Appendix R diesel generator (September 2006 and December 2006): no significant corrosion or wear.

The applicant stated that "use of proven monitoring techniques and acceptance criteria assures continued program effectiveness in managing aging effects for passive components."

SRP-LR Section A.1.2.3.10 establishes the following recommendations for discussion of operating experience for existing AMPs:

> Operating experience with existing programs should be discussed. The operating experience of aging management programs, including past corrective actions resulting in program enhancements or additional programs, should be considered. A past failure would not necessarily invalidate an aging management program because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information can show where an existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that the effects of aging will be managed adequately so that the structure and component intended function(s) will be maintained during the period of extended operation.

The staff noted that the applicant had indicated that the program was already implementing inspections on the IP2 and IP3 reactor building polar cranes, IP2 and IP3 recirculation pumps and related system components, IP2 diesel generator building floor drain backwater valves, IP2 and IP3 emergency diesel generators (EDGs), the security generator, and the IP3 Appendix R fire protection diesel generator. The staff noted that of the inspections performed, the applicant's indicated that there were no indications of aging only for the inspections that were performed on polar cranes, and on the IP2 diesel generator building floor drain backwater valves. The staff noted that, for the aging statements on the inspections that were performed on the other components, the statements were ambiguous in that the applicant did not distinguish whether aging had been detected but that the amount of aging was determined to be acceptable when compared to the acceptance criteria for the aging effect or whether the inspections did not identify the presence of aging effects in the components being inspected. Thus, the staff needed additional information on the following aging statements that were made in the "operating experience" program element discussion for the AMP:

1. Inspection statement for the IP3 NaOH tank – requesting clarification on the statement "no deficiencies. Ultrasonic measurement of wall thickness was satisfactory" and in particular whether loss of material had been detected in the component even though the amount of loss material was found to be acceptable.

2. Inspection statement for the IP2 and IP3 recirculation pumps and related system components – requesting clarification on the statement "no deficiencies" and in particular whether this means that no aging effects had been detected, or that some specific aging (e.g., cracking, loss of material, etc.) I had been detected in the component even though the amount of aging was found to be acceptable.

3. Inspection statements for the IP2 and IP3 EDGs, the security diesel generator, and the IP3 Appendix R fire protection diesel generator – requesting clarification on the statements "no unacceptable loss of material" and "no significant corrosion or wear" and in particular whether this means that no loss of material by corrosion, erosion or wear (or other mechanisms) was detecting or that some loss of material was detected in the components even though the amount of loss of material was found to be acceptable.

The staff sought clarification on whether any aging effects had been detected in these components as a result of the past periodic surveillance and Preventive maintenance inspections that had been performed on these components, and if so, identification of what the appropriate corrective actions were for dispositioning these components in order to ensure that the program is implementing its appropriate "corrective actions" program element criteria. In RAI 3.0.3.3.7.1-1, Part 5, the staff asked the applicant to clarify the meaning of its references to no unacceptable degradation. This was identified as Open Item 3.0.3.3.7-1, Part 5.

The applicant responded to RAI 3.0.3.3.7-1, Part 5 in a letter dated January 27, 2009. A portion of this response was amended by letter dated June 30, 2009, due to a plant modification which eliminated the sodium hydroxide (liquid injection) from the containment spray system. In its response, the applicant clarified that the inspections of the IP2 and IP3 recirculation pumps, IP2 and IP3 EDGs, the security generator, and the IP3 Appendix R fire protection diesel generator found no evidence of loss of material. The staff finds that the applicant's response to RAI 3.0.3.3.7-1, Part 5 resolves the staff's issue with the operating experience discussion because it clarifies that the inspections of these components confirmed that there was no loss of material occurring in the components. Thus, the staff finds the applicant's "operating experience" program element, as modified by the information in the applicant's response to RAI 3.0.3.3.7-1, Part 5, to be acceptable because the applicant has clarified that it has been performing periodic condition monitoring of the subject components as part of the periodic inspections that are implemented as part of this AMP. The staff concludes that RAI 3.0.3.3.7-1, Part 5 is resolved and Open Item 3.0.3.3.7-1, Part 5 is closed. The staff notes that the applicant's operating experience discussion for this AMP, as supplemented in the applicant's response to RAI 3.0.3.3.7-1, Part 5, meets the recommendation in SRP-LR Section A.1.2.3.10 because the applicant adequately summarized the periodic inspections that the applicant had performed under this AMP over the last 5 years of plant operation and had summarized the results of the inspections, demonstrating there had not been any age-related degradation in the components that were inspected under this AMP.

Based on this review, the staff finds that the applicant's "operating experience" program element, as supplemented by the applicant's response to RAI 3.0.3.3.7-1, Part 5, is acceptable because it meets the recommendation in SRP-LR Section A.1.2.3.10 to discuss the relevant operating experience for the components that have been inspected through the implementation of an existing AMP.

The staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.28 and A.3.1.28, the applicant provided the UFSAR supplement for the Periodic Surveillance and Preventive Maintenance Program. The staff reviewed these sections and finds the UFSAR supplement information is an adequate summary description of the program, as required by 10 CFR 54.21(d). The staff notes that the UFSAR Supplement summary description provided an acceptable summary listing of the components and activities that are within scope of this AMP. The staff also notes that, in this UFSAR Supplement, the applicant included LRA Commitment 21, in which the applicant committed to enhance the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements of the AMP as follows: "Program activity guidance documents will be developed or revised as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation."

Based on this review, the staff finds that the applicant has provided an acceptable UFSAR Supplement summary description for this AMP because: (1) the summary description appropriately summarizes the components and activities that are within the scope of the AMP, (2) the applicant has clearly defined what the program elements are for this AMP, and has provided its bases on why these program elements are in conformance with the recommendations of SRP-LR Section A.1.2.3, and (3) in LRA Commitment No. 21, the applicant has committed to enhance the program to develop activity documents to reflect the program elements for this AMP. The staff concludes that RAI 3.0.3.3.7-1, Parts 1, 2, 3, ,4 and 5 are resolved and Open Item 3.0.3.3.7-1, Parts 1, 2, 3, 4, and 5 are closed with respect to the acceptability of the UFSAR Supplement summary description for this AMP.

Conclusion. On the basis of its review of the applicant's Periodic Surveillance and Preventive Maintenance Program, the staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.8 Water Chemistry Control - Auxiliary Systems Program

Summary of Technical Information in the Application. LRA Section B.1.39 and Amendment 1 to the LRA, Attachment 1, describe the existing Water Chemistry Control - Auxiliary Systems Program as a plant-specific program.

The Water Chemistry Control - Auxiliary Systems Program manages loss of material and cracking for components exposed to treated water by sampling and analysis to minimize component exposure to aggressive environments for the stator cooling water systems. The One-Time Inspection Program for Water Chemistry utilizes inspections or nondestructive evaluations of representative samples to verify whether the Water Chemistry Control - Auxiliary Systems Program has been effective in managing aging effects.

Staff Evaluation. In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in LRA Section B.1.39 on the applicant's demonstration of the Water Chemistry Control - Auxiliary Systems 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 for the period of extended operation.

The staff reviewed the Water Chemistry Control - Auxiliary Systems Program against the AMP elements found in the GALL Report, in SRP-LR Section A.1.2.3, and in SRP-LR Table A.1-1, focusing on how the program manages aging effects through the effective incorporation of 10 elements ((1) "scope of the program," (2) "preventive actions," (3) "parameters monitored or inspected," (4) "detection of aging effects," (5) "monitoring and trending," (6) "acceptance criteria," (7) "corrective actions," (8) "confirmation process," (9) "administrative controls," and (10) "operating experience").

In Audit Item 90, the staff asked the applicant to describe past and present surveillance tests, sampling, and analysis activities for managing the effects of aging on components within the scope of this AMP. By letter dated December 18, 2007, the applicant stated that since thickness measurements are performed every five years under the Periodic Surveillance and Preventive Maintenance Program, use of the Water Chemistry Control - Auxiliary Systems Program for the NaOH tank is not required. By letter dated December 18, 2007 the applicant amended the LRA to remove the Water Chemistry Control - Auxiliary Systems Program as an aging management program for the NaOH tank. By letter dated June 30, 2009, the applicant amended the LRA due to a plant modification which eliminated the NaOH tank and piping and fittings from the containment spray system.

The applicant indicated that program elements (7) "corrective actions," (8) "confirmation process," and (9) "administrative controls" are parts of the site-controlled QA program. The staff's evaluation of the QA program is in SER Section 3.0.4. Evaluation of the remaining seven elements follows:

(1) Scope of the Program - LRA Section B.1.39, as amended, states that program activities include sampling and analysis of the stator cooling water system to minimize component exposure to aggressive environments.

The staff reviewed the program basis document and determined that it adequately describes the specific system and components in the scope of this program for which aging will be managed. The staff reviewed the system and determined that it uses treated water as the cooling medium. Since this program manages aging by monitoring and analyzing the coolant, the stator cooling water systems are appropriate for inclusion in the scope of this program.

The staff confirmed that the "scope of the program" program element satisfies the guidance in SRP-LR Section A.1.2.3.1. The staff finds this program element acceptable.

(2) Preventive Actions - LRA Section B.1.39 states that the program includes monitoring and control of treated water for components included in the scope of the program to minimize exposure to aggressive environments, thereby mitigating the effects of aging.

The staff determined that the program includes monitoring and control of water chemistry to minimize component exposure to aggressive water environments. The aging effects managed by this program are loss of material, fouling, and cracking, which are directly related to the purity and aggressiveness of the water to which the

components are exposed. Therefore, monitoring and controlling the water chemistry is an effective means of managing loss of material for the components in the scope of this program. The staff finds these preventive actions to be appropriate to manage the aging effects for which this program is credited.

The staff confirmed that the "preventive actions" program element satisfies the guidance in SRP-LR Section A.1.2.3.2. The staff finds this program element acceptable.

(3) Parameters Monitored or Inspected - LRA Section B.1.39, as amended, states that treated water is monitored to mitigate degradation through control of impurities. Stator cooling water is monitored for copper and conductivity monthly.

The staff noted that this program is credited to manage loss of material, fouling, and cracking for components exposed to treated water. These aging effects are directly related to the purity and aggressiveness of the water, which are based on the conductivity, pH, and dissolved oxygen in the water. Therefore, monitoring these parameters is an effective means of assessing the purity and aggressiveness of the water, and determining whether corrective actions are needed to modify the water chemistry. On this basis, the staff finds these parameters acceptable for this program.

In Audit Item 91, the staff asked the applicant to describe the procedures used to perform surveillance activities and the basis for acceptance criteria and sample / test frequencies. By letter dated December 18, 2007, the applicant stated that the stator cooling water systems are high purity systems in which poor oxygen control can cause an increase in copper corrosion products. Based on this experience, stator cooling water is monitored monthly for conductivity and copper. The staff determined that the applicant's basis for selection of parameters is acceptable since it considers vendor specifications, industry standards, and operating experience.

The staff confirmed that the "parameters monitored or inspected" program element satisfies the guidance in SRP-LR Section A.1.2.3.3. The staff finds this program element acceptable.

(4) Detection of Aging Effects - LRA Section B.1.39 states that the program manages loss of material and cracking for stainless steel, carbon steel, and copper alloy components included in the scope of the program. This is a mitigation program and does not provide for detection of aging effects. However, the One-Time Inspection Program describes inspections planned to verify the effectiveness of water chemistry control programs to ensure that significant degradation has not occurred and component intended function is maintained during the period of extended operation.

The staff determined that this program includes monitoring and control of water chemistry to manage loss of material, fouling, and cracking of auxiliary system components. These aging effects are directly related to the purity and aggressiveness of the water; therefore, monitoring these parameters will provide an effective means of mitigating aging. The monitoring frequencies will provide for timely detection of adverse water chemistry such that corrective actions can be taken prior to a loss of component intended function. The staff finds these activities appropriate for managing the aging effects for which this program is credited since they will provide reasonable assurance

that the component intended function will be maintained for the extended period of operation.

The staff confirmed that the "detection of aging effects" program element satisfies the guidance in SRP-LR Section A.1.2.3.4. The staff finds this program element acceptable.

(5) Monitoring and Trending - LRA Section B.1.39 states that initially, analytical results are interpreted by the chemist performing the analysis. Abnormal trends in the chemistry data are evaluated by that person given the status of that system at that time. Any significant abnormality or trend, as well as out of specification or out of control band chemistry parameter is brought to the attention of the Shift Manager and Chemistry Management. Values from analyses are archived for long-term trending and review. Trending is not required to predict the extent of degradation since maintaining parameters within acceptance criteria prevents degradation. Operating experience indicates effectiveness in preventing aging effects if parameters are maintained within limits.

The staff reviewed the applicant's program implementing procedures and determined that appropriate administrative controls and program activities are in place to monitor and trend chemistry parameters to identify aging effects and take corrective actions prior to the loss of a component intended function. The staff finds that the applicant's use of site chemistry staff reviews and quarterly group data review sessions is an effective means of monitoring water chemistry parameters.

The staff confirmed that the "monitoring and trending" program element satisfies the guidance in SRP-LR Section A.1.2.3.5. The staff finds this program element acceptable.

(6) Acceptance Criteria - LRA Section B.1.39, as amended, states the following acceptance criteria for stator cooling water systems:

Parameter	**Acceptance Criteria**
Conductivity	< 0.5 μmhos/cm
Copper	< 20 ppb

The staff confirmed that the "acceptance criteria" program element satisfies the guidance in SRP-LR Section A.1.2.3.6. The staff finds this program element acceptable.

(10) Operating Experience - LRA Section B.1.39 states that the QA audits of the chemistry control program in 2005 and 2006 found compliance with all guidelines (INPO 03-004, EPRI TR-105714, and TR-102134) for chemistry performance satisfactory with sufficient parameters measured to detect abnormal conditions or condition changes. The audits found all chemistry parameters maintained within specified bands and auxiliary systems treated and controlled to industry guidelines. Adherence to chemistry specifications assures continued program effectiveness in managing the effects of aging.

In Audit Item 90, the staff asked the applicant about past and present surveillance tests, sampling and analysis activities for managing the effects of aging on components within the scope of this AMP. By letter dated December 18, 2007, the applicant stated that

recent monthly tests of stator cooling water samples have been within the specification. The applicant further stated that monthly stator cooling water analysis will continue per the requirements of the applicant's procedure.

The staff reviewed the operating experience provided in the LRA, and the applicant's operating experience review results report, and determined that there were no aging effects identified that are not bounded by industry operating experience. Recent operating experience indicated that all chemistry parameters have been maintained within specified bands and auxiliary systems treated and controlled to industry guidelines. This operating experience provides objective evidence that this program is effective in detecting and managing aging effects in the auxiliary cooling water systems.

The staff confirmed that the "operating experience" program element satisfies the guidance in SRP-LR Section A.1.2.3.10. The staff finds this program element acceptable.

UFSAR Supplement. In LRA Sections A.2.1.38 and A.3.1.38, the applicant provided the UFSAR supplement for the Water Chemistry Control - Auxiliary Systems Program. In Amendment 1, dated December 18, 2007, the applicant revised the second paragraphs of Sections A.2.1.38 and A.3.1.38 as follows:

"Program activities include sampling and analysis to minimize component exposure to aggressive environments for stator cooling water systems."

The staff reviewed these sections and finds the UFSAR supplement information is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its review of the applicant's Water Chemistry Control - Auxiliary Systems Program, the staff concludes that the applicant has demonstrated that 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 UFSAR supplement for this program and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.4 QA Program Attributes Integral to Aging Management Programs

3.0.4.1 Summary of Technical Information in the Application

In Sections A.2.1, "Aging Management Program and Activities," and B.0.3, "Corrective Actions, Confirmation Process and Administrative Controls," of the LRA, the applicant described the elements of corrective action, confirmation process, and administrative controls that are applied to the AMPs for both safety-related and nonsafety-related components. The Entergy Quality Assurance Program (EQAP) is used which includes the elements of corrective action, confirmation process, and administrative controls. Corrective actions, confirmation, and administrative controls are applied in accordance with the EQAP regardless of the safety classification of the components. LRA Sections A.2.1 and B.0.3, stated that the EQAP implements the requirements of 10 CFR 50, Appendix B, and is consistent with the GALL Report.

3.0.4.2 *Staff Evaluation*

Pursuant to 10 CFR 54.21(a)(3), the 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. SRP-LR, BTP RLSB-1, "Aging Management Review – Generic," describes ten elements of an acceptable AMP. Elements (7), (8), and (9) are associated with the QA activities of "corrective actions," "confirmation process," and "administrative controls." BTP RLSB-1 Table A.1-1, "Elements of an Aging Management Program for License Renewal," provides the following description of these program elements:

(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 are completed and effective.

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

SRP-LR BTP IQMB-1, "Quality Assurance for Aging Management Programs," notes that AMP aspects that affect the 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 applicant may use the existing 10 CFR Part 50 Appendix B QA program to address the elements of "corrective actions," "confirmation process," and "administrative controls." BTP IQMB-1 provides the following guidance on the QA attributes of AMPs:

1. Safety-related structures and components are subject to 10 CFR Part 50 Appendix B requirements, which are adequate to address all quality-related aspects of an aging management program consistent with the CLB of the facility for the period of extended operation.

2. For nonsafety-related structures and components that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its 10 CFR Part 50 Appendix B program to include these structures and components to address corrective actions, the confirmation process, and administrative controls for aging management during the period of extended operation. The reviewer should verify that the applicant has documented such a commitment in the FSAR supplement in accordance with 10 CFR 54.21(d).

The NRC staff reviewed the applicant's aging management programs (AMPs) described in Appendix A, "Updated Final Safety Analysis Report Supplement," and Appendix B, "Aging Management Programs and Activities," of the LRA, and the associated implementing documents. The purpose of this review was to ensure that the quality assurance attributes (corrective action, confirmation process, and administrative controls) are consistent with the staff's guidance described in SRP-LR BTP RLSB-1 and BTP IQMPB-1. In addition, the staff reviewed the enhancements for the "corrective actions" program element as specified in LRA Sections B.1.16 and B.1.26, and determined that the enhancements did not affect the

applicant's application of the EQAP. Based on the NRC staff's evaluation, the descriptions of the AMPs and their associated quality attributes provided in Appendix A, Section A.2.1, and Appendix B, Section B.0.3, of the LRA were determined to be consistent with the staff's position regarding quality assurance for aging management.

3.0.4.3 *Conclusion*

On the basis of the NRC staff's evaluation, the descriptions and applicability of the plant-specific AMPs and their associated quality attributes provided in Appendix A, Section A.2.1, and Appendix B, Section B.0.3 of the LRA, the quality assurance elements "corrective actions," "confirmation process," and "administrative controls," as applied to the applicant's programs were determined to be consistent with the staff's position regarding QA for aging management. The staff concludes that the QA attributes "corrective action," "confirmation process," and "administrative control," of the applicant's programs are consistent with 10 CFR 54.21(a)(3).

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 of:

- reactor vessel
- reactor vessel internals
- reactor coolant system and pressurizer
- steam generator

3.1.1 Summary of Technical Information in the Application

LRA Section 3.1 provides AMR results for the reactor vessel, reactor vessel internals, and reactor coolant system components and component groups. LRA Table 3.1.1, "Summary of Aging Management Programs for the Reactor Coolant System Evaluated in Chapter IV of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the reactor vessel, reactor vessel internals, and reactor coolant system components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included 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.

3.1.2 Staff Evaluation

The staff reviewed LRA Section 3.1 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the reactor vessel, reactor vessel internals, and reactor coolant system components within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended functions will be

maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff conducted an onsite audit of AMRs to ensure the applicant's claim that certain AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in SER Section 3.1.2.1.

In the onsite audit, the staff also selected AMRs 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 SRP-LR Section 3.1.2.2 acceptance criteria. The staff's audit evaluations are documented in SER Section 3.1.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed were appropriate for the material-environment combinations specified. The staff's evaluations are documented in SER Section 3.1.2.3.

For components which the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR line items and the plant's operating experience to verify the applicant's claims.

Table 3.1-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.1 and addressed in the GALL Report.

Table 3.1-1 Staff Evaluation for Reactor Vessel, Reactor Vessel Internals and Reactor Coolant System Components in the GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel pressure vessel support skirt and attachment welds (3.1.1-1)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	See SER Section 3.1.2.2.1

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel; steel with nickel alloy or stainless steel cladding; nickel alloy reactor vessel components: flanges; nozzles; penetrations; safe ends; thermal sleeves; vessel shells, heads and welds (3.1.1-2)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel alloy or stainless steel cladding; nickel alloy reactor coolant pressure boundary piping, piping components, and piping elements exposed to reactor coolant (3.1.1-3)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)
Steel pump and valve closure bolting (3.1.1-4)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) check Code limits for allowable cycles (less than 7000 cycles) of thermal stress range	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.1)
Stainless steel and nickel alloy reactor vessel internals components (3.1.1-5)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)
Nickel Alloy tubes and sleeves in a reactor coolant and secondary feedwater/steam environment (3.1.1-6)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel and stainless steel reactor coolant pressure boundary closure bolting, head closure studs, support skirts and attachment welds, pressurizer relief tank components, SG components, piping and components external surfaces and bolting (3.1.1-7)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c)	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)
Steel; stainless steel; and nickel alloy reactor coolant pressure boundary piping, piping components, piping elements; flanges; nozzles and safe ends; pressurizer vessel shell heads and welds; heater sheaths and sleeves; penetrations; and thermal sleeves (3.1.1-8)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)
Steel; stainless steel; steel with nickel alloy or stainless steel cladding; nickel alloy reactor vessel components: flanges; nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads and welds (3.1.1-9)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel; steel with nickel alloy or stainless steel cladding; nickel alloy steam generator components (flanges; penetrations; nozzles; safe ends, lower heads and welds) (3.1.1-10)	Cumulative fatigue damage	TLAA, evaluated in accordance with 10 CFR 54.21(c) and environmental effects are to be addressed for Class 1 components	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.1)
Steel top head enclosure (without cladding) top head nozzles (vent, top head spray or RCIC, and spare) exposed to reactor coolant (3.1.1-11)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2)
Steel steam generator shell assembly exposed to secondary feedwater and steam (3.1.1-12)	Loss of material due to general, pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Water Chemistry Control - Primary and Secondary One-Time Inspection	Consistent with GALL Report (see SER Section 3.1.2.2.2(1))
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-13)	Loss of material due to general (steel only), pitting, and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2(2))
Stainless steel, nickel alloy, and steel with nickel alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds (3.1.1-14)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2(3))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-15)	Loss of material due to pitting and crevice corrosion	Water Chemistry and One-Time Inspection	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.2(3))
Steel steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam (3.1.1-16)	Loss of material due to general, pitting, and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry and, for Westinghouse Model 44 and 51 S/G, if general and pitting corrosion of the shell is known to exist, additional inspection procedures are to be developed.	Yes	Inservice Inspection and Water Chemistry Control - Primary and Secondary	Consistent with GALL Report (see SER Section 3.1.2.2.2(4))
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds (3.1.1-17)	Loss of fracture toughness due to neutron irradiation embrittlement	TLAA, evaluated in accordance with 10 CFR 50, Appendix G, and RG 1.99. The applicant may choose to demonstrate that the materials of the nozzles are not controlling for the TLAA evaluations.	Yes	TLAA	Consistent with GALL Report (see SER Section 3.1.2.2.3(1))
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds; safety injection nozzles (3.1.1-18)	Loss of fracture toughness due to neutron irradiation embrittlement	Reactor Vessel Surveillance	Yes	Reactor Vessel Surveillance	Consistent with GALL Report (see SER Section 3.1.2.2.3(2))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation In GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy top head enclosure vessel flange leak detection line (3.1.1-19)	Cracking due to stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC)	A plant-specific aging management program is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.4(1))
Stainless steel isolation condenser components exposed to reactor coolant (3.1.1-20)	Cracking due to SCC and IGSCC	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and plant-specific verification program	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.4(2))
Reactor vessel shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process (3.1.1-21)	Crack growth due to cyclic loading	TLAA	Yes	Not applicable	Not applicable (see SER Section 3.1.2.2.5)
Stainless steel and nickel alloy reactor vessel internals components exposed to reactor coolant and neutron flux (3.1.1-22)	Loss of fracture toughness due to neutron irradiation embrittlement, void swelling	FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Committed to Reactor Vessel Internals Inspection plan being developed by the industry	Consistent with GALL Report (see SER Section 3.1.2.2.6)
Stainless steel reactor vessel closure head flange leak detection line and bottom-mounted instrument guide tubes (3.1.1-23)	Cracking due to SCC	A plant-specific aging management program is to be evaluated.	Yes	Inservice Inspection and Water Chemistry Control - Primary and Secondary	Consistent with GALL Report (see SER Section 3.1.2.2.7(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Class 1 cast austenitic stainless steel piping, piping components, and piping elements exposed to reactor coolant (3.1.1-24)	Cracking due to SCC	Water Chemistry and, for CASS components that do not meet the NUREG-0313 guidelines, a plant-specific AMP	Yes	Water Chemistry Control - Primary and Secondary and Thermal Embrittlement of Cast Austenitic Stainless Steel (CASS) supplemented by the Inservice Inspection Program	Consistent with GALL Report (see SER Section 3.1.2.2.7(2))
Stainless steel jet pump sensing line (3.1.1-25)	Cracking due to cyclic loading	A plant-specific aging management program is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.8(1))
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-26)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD) and plant-specific verification program	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.8(2))
Stainless steel and nickel alloy reactor vessel internals screws, bolts, tie rods, and hold-down springs (3.1.1-27)	Loss of preload due to stress relaxation	FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Committed to Reactor Vessel Internals Inspection plan being developed by the industry	Consistent with GALL Report (see SER Section 3.1.2.2.9)
Steel steam generator feedwater impingement plate and support exposed to secondary feedwater (3.1.1-28)	Loss of material due to erosion	A plant-specific aging management program is to be evaluated.	Yes	None	Not applicable (see SER Section 3.1.2.2.10)
Stainless steel steam dryers exposed to reactor coolant (3.1.1-29)	Cracking due to flow-induced vibration	A plant-specific aging management program is to be evaluated.	Yes	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.2.11)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel reactor vessel internals components (e.g., Upper internals assembly, RCCA guide tube assemblies, Baffle/former assembly, Lower internal assembly, shroud assemblies, Plenum cover and plenum cylinder, Upper grid assembly, Control rod guide tube (CRGT) assembly, Core support shield assembly, Core barrel assembly, Lower grid assembly, Flow distributor assembly, Thermal shield, Instrumentation support structures) (3.1.1-30)	Cracking due to SCC, irradiation-assisted SCC	Water Chemistry and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval less than 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Water Chemistry Control – Primary and Secondary Committed to Reactor Vessel Internals Inspection plan being developed by the industry	Consistent with GALL Report (see SER Section 3.1.2.2.12)
Nickel alloy and steel with nickel alloy cladding piping, piping component, piping elements, penetrations, nozzles, safe ends, and welds (other than reactor vessel head); pressurizer heater sheaths, sleeves, diaphragm plate, manways and flanges; core support pads/core guide lugs (3.1.1-31)	Cracking due to primary water stress corrosion cracking (PWSCC)	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and FSAR supplement commitment to implement applicable plant commitments to (1) NRC Orders, Bulletins, and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	Inservice Inspection, Water Chemistry Control - Primary and Secondary, and Nickel Alloy Inspection Programs (with commitment)	Consistent with GALL Report (see SER Section 3.1.2.2.13)
Steel steam generator feedwater inlet ring and supports (3.1.1-32)	Wall thinning due to flow-accelerated corrosion	A plant-specific aging management program is to be evaluated.	Yes	Steam Generator Integrity	Consistent with GALL Report (see SER Section 3.1.2.2.14)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy reactor vessel internals components (3.1.1-33)	Changes in dimensions due to void swelling	FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval less than 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Committed to Reactor Vessel Internals Inspection plan being developed by the industry	Consistent with GALL Report (see SER Section 3.1.2.2.15)
Stainless steel and nickel alloy reactor control rod drive head penetration pressure housings (3.1.1-34)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and for nickel alloy, comply with applicable NRC Orders and provide a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	Inservice Inspection, Water Chemistry Control - Primary and Secondary, and Reactor Vessel Head Penetration Inspection (with commitment)	Consistent with GALL Report (see SER Section 3.1.2.2.16(1))
Steel with stainless steel or nickel alloy cladding primary side components; steam generator upper and lower heads, tubesheets and tube-to-tube sheet welds (3.1.1-35)	Cracking due to SCC and PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and for nickel alloy, comply with applicable NRC Orders and provide a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	Inservice Inspection and Water Chemistry Control – Primary and Secondary for carbon steel with stainless steel clad. Water Chemistry Control – Primary and Secondary and Steam Generator Integrity for carbon steel with Nickel alloy clad (with commitment).	Consistent with GALL Report (see SER Section 3.1.2.2.16(1))

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy, stainless steel pressurizer spray head (3.1.1-36)	Cracking due to SCC and PWSCC	Water Chemistry and One-Time Inspection and, for nickel alloy welded spray heads, comply with applicable NRC Orders and provide a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	Not used	Not applicable (see SER Section 3.1.2.2.16(2))
Stainless steel and nickel alloy reactor vessel internals components (e.g., Upper internals assembly, RCCA guide tube assemblies, Lower internal assembly, CEA shroud assemblies, Core shroud assembly, Core support shield assembly, Core barrel assembly, Lower grid assembly, Flow distributor assembly) (3.1.1-37)	Cracking due to SCC, PWSCC, irradiation-assisted SCC	Water Chemistry and FSAR supplement commitment to (1) participate in industry RVI aging programs (2) implement applicable results (3) submit for NRC approval > 24 months before the extended period an RVI inspection plan based on industry recommendation.	No, but licensee commitment needs to be confirmed	Water Chemistry Control – Primary and Secondary and committed to Reactor Vessel Internals Inspection plan being developed by the industry	Consistent with GALL Report (see SER Section 3.1.2.2.17)
Steel (with or without stainless steel cladding) control rod drive return line nozzles exposed to reactor coolant (3.1.1-38)	Cracking due to cyclic loading	BWR Control Rod Drive Return Line Nozzle	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel (with or without stainless steel cladding) feedwater nozzles exposed to reactor coolant (3.1.1-39)	Cracking due to cyclic loading	BWR Feedwater Nozzle	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy penetrations for control rod drive stub tubes instrumentation, jet pump instrumentation, standby liquid control, flux monitor, and drain line exposed to reactor coolant (3.1.1-40)	Cracking due to SCC, IGSCC, cyclic loading	BWR Penetrations and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy piping, piping components, and piping elements greater than or equal to 4 NPS; nozzle safe ends and associated welds (3.1.1-41)	Cracking due to SCC and IGSCC	BWR Stress Corrosion Cracking and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy vessel shell attachment welds exposed to reactor coolant (3.1.1-42)	Cracking due to SCC and IGSCC	BWR Vessel ID Attachment Welds and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel fuel supports and control rod drive assemblies control rod drive housing exposed to reactor coolant (3.1.1-43)	Cracking due to SCC and IGSCC	BWR Vessel Internals and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy core shroud, core plate, core plate bolts, support structure, top guide, core spray lines, spargers, jet pump assemblies, control rod drive housing, nuclear instrumentation guide tubes (3.1.1-44)	Cracking due to SCC, IGSCC, irradiation-assisted SCC	BWR Vessel Internals and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to reactor coolant (3.1.1-45)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Nickel alloy core shroud and core plate access hole cover (mechanical covers) (3.1.1-46)	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy reactor vessel internals exposed to reactor coolant (3.1.1-47)	Loss of material due to pitting and crevice corrosion	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel and stainless steel Class 1 piping, fittings and branch connections less than NPS 4 exposed to reactor coolant (3.1.1-48)	Cracking due to SCC, IGSCC (for stainless steel only), and thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Nickel alloy core shroud and core plate access hole cover (welded covers) (3.1.1-49)	Cracking due to SCC, IGSCC, irradiation-assisted SCC	Inservice Inspection (IWB, IWC, and IWD), Water Chemistry, and, for BWRs with a crevice in the access hole covers, augmented inspection using UT or other demonstrated acceptable inspection of the access hole cover welds	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
High-strength low alloy steel top head closure studs and nuts exposed to air with reactor coolant leakage (3.1.1-50)	Cracking due to SCC and IGSCC	Reactor Head Closure Studs	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Cast austenitic stainless steel jet pump assembly castings; orificed fuel support (3.1.1-51)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	Not applicable	Not applicable to PWRs (see SER Section 3.1.2.1.1)
Steel and stainless steel reactor coolant pressure boundary (RCPB) pump and valve closure bolting, manway and holding bolting, flange bolting, and closure bolting in high-pressure and high-temperature systems (3.1.1-52)	Cracking due to SCC, loss of material due to wear, loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	Bolting Integrity	Consistent with GALL Report (see SER Section 3.1.2.1.2)
Steel piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-53)	Loss of material due to general, pitting, and crevice corrosion	Closed-Cycle Cooling Water System	No	Water Chemistry Control – Closed Cooling Water	Consistent with GALL Report
Copper alloy piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-54)	Loss of material due to pitting, crevice, and galvanic corrosion	Closed-Cycle Cooling Water System	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Cast austenitic stainless steel Class 1 pump casings, and valve bodies and bonnets exposed to reactor coolant greater than 250°C (less than 482°F) (3.1.1-55)	Loss of fracture toughness due to thermal aging embrittlement	Inservice Inspection (IWB, IWC, and IWD). Thermal aging susceptibility screening is not necessary, inservice inspection requirements are sufficient for managing these aging effects. ASME Code Case N-481 also provides an alternative for pump casings.	No	Inservice Inspection	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy greater than 15% Zn piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-56)	Loss of material due to selective leaching	Selective Leaching of Materials	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Cast austenitic stainless steel Class 1 piping, piping component, and piping elements and control rod drive pressure housings exposed to reactor coolant greater than 250°C (less than 482°F) (3.1.1-57)	Loss of fracture toughness due to thermal aging embrittlement	Thermal Aging Embrittlement of CASS	No	Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	Consistent with GALL Report
Steel reactor coolant pressure boundary external surfaces exposed to air with borated water leakage (3.1.1-58)	Loss of material due to boric acid corrosion	Boric Acid Corrosion	No	Boric Acid Corrosion Prevention	Consistent with GALL Report
Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam (3.1.1-59)	Wall thinning due to flow-accelerated corrosion	Flow-Accelerated Corrosion	No	Flow-Accelerated Corrosion	Consistent with GALL Report (see SER Section 3.1.2.1.5)
Stainless steel flux thimble tubes (with or without chrome plating) (3.1.1-60)	Loss of material due to wear	Flux Thimble Tube Inspection	No	Flux Thimble Tube Inspection	Consistent with GALL Report
Stainless steel, steel pressurizer integral support exposed to air with metal temperature up to 288°C (550°F) (3.1.1-61)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD)	No	Inservice Inspection	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel with stainless steel cladding reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant (3.1.1-62)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD)	No	Inservice Inspection	Consistent with GALL Report (see SER Section 3.1.2.1.3)
Steel reactor vessel flange, stainless steel and nickel alloy reactor vessel internals exposed to reactor coolant (e.g., upper and lower internals assembly, CEA shroud assembly, core support barrel, upper grid assembly, core support shield assembly, lower grid assembly) (3.1.1-63)	Loss of material due to wear	Inservice Inspection (IWB, IWC, and IWD)	No	Inservice Inspection	Consistent with GALL Report
Stainless steel and steel with stainless steel or nickel alloy cladding pressurizer components (3.1.1-64)	Cracking due to SCC, PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry	No	Inservice Inspection and Water Chemistry Control – Primary and Secondary (for steel with stainless steel or nickel alloy clad)	Consistent with GALL Report (see SER Section 3.1.2.1.3)
Nickel alloy reactor vessel upper head and control rod drive penetration nozzles, instrument tubes, head vent pipe (top head), and welds (3.1.1-65)	Cracking due to PWSCC	Inservice Inspection (IWB, IWC, and IWD) and Water Chemistry and Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors	No	Inservice Inspection, Water Chemistry Control – Primary and Secondary, and Nickel Alloy Inspection	Consistent with GALL Report (see SER Section 3.1.2.1.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator secondary manways and handholds (cover only) exposed to air with leaking secondary-side water and/or steam (3.1.1-66)	Loss of material due to erosion	Inservice Inspection (IWB, IWC, and IWD) for Class 2 components	No	Not used	See SER Section 3.1.2.1.6
Steel with stainless steel or nickel alloy cladding; or stainless steel pressurizer components exposed to reactor coolant (3.1.1-67)	Cracking due to cyclic loading	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Inservice Inspection and Water Chemistry Control – Primary and Secondary	Consistent with GALL Report (see SER Section 3.1.2.1.3)
Stainless steel, steel with stainless steel cladding Class 1 piping, fittings, pump casings, valve bodies, nozzles, safe ends, manways, flanges, CRD housing; pressurizer heater sheaths, sleeves, diaphragm plate; pressurizer relief tank components, reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings (3.1.1-68)	Cracking due to SCC	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Inservice Inspection, Water Chemistry Control – Primary and Secondary, and One Time Inspection (for non-ISI components)	Consistent with GALL Report (see SER Section 3.1.2.1.3)
Stainless steel, nickel alloy safety injection nozzles, safe ends, and associated welds and buttering exposed to reactor coolant (3.1.1-69)	Cracking due to SCC, PWSCC	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Inservice Inspection and Water Chemistry Control – Primary and Secondary (for SS components only)	Consistent with GALL Report (see SER Section 3.1.2.1.3)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel; steel with stainless steel cladding Class 1 piping, fittings and branch connections less than NPS 4 exposed to reactor coolant (3.1.1-70)	Cracking due to SCC, thermal and mechanical loading	Inservice Inspection (IWB, IWC, and IWD), Water chemistry, and One-Time Inspection of ASME Code Class 1 Small-bore Piping	No	Inservice Inspection, Water Chemistry Control – Primary and Secondary and One Time Inspection (small bore piping)	Consistent with GALL Report
High-strength low alloy steel closure head stud assembly exposed to air with reactor coolant leakage (3.1.1-71)	Cracking due to SCC; loss of material due to wear	Reactor Head Closure Studs	No	Reactor Head Closure Studs	Consistent with GALL Report
Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater/steam (3.1.1-72)	Cracking due to OD SCC and intergranular attack, loss of material due to fretting and wear	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Integrity and Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Nickel alloy steam generator tubes, repair sleeves, and tube plugs exposed to reactor coolant (3.1.1-73)	Cracking due to PWSCC	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Integrity and Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Chrome plated steel, stainless steel, nickel alloy steam generator anti-vibration bars exposed to secondary feedwater/steam (3.1.1-74)	Cracking due to SCC, loss of material due to crevice corrosion and fretting	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Integrity, Water Chemistry Control – Primary and Secondary and One Time Inspection	Consistent with GALL Report (see SER Sections 3.1.2.1.4, 3.1.2.1.7, and 3.1.2.1.8)
Nickel alloy once-through steam generator tubes exposed to secondary feedwater/steam (3.1.1-75)	Denting due to corrosion of carbon steel tube support plate	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator tube support plate, tube bundle wrapper exposed to secondary feedwater/steam (3.1.1-76)	Loss of material due to erosion, general, pitting, and crevice corrosion, ligament cracking due to corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Steam Generator Integrity and Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater/steam (3.1.1-77)	Loss of material due to wastage and pitting corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Steel steam generator tube support lattice bars exposed to secondary feedwater/steam (3.1.1-78)	Wall thinning due to flow-accelerated corrosion	Steam Generator Tube Integrity and Water Chemistry	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Nickel alloy steam generator tubes exposed to secondary feedwater/steam (3.1.1-79)	Denting due to corrosion of steel tube support plate	Steam Generator Tube Integrity; Water Chemistry and, for plants that could experience denting at the upper support plates, evaluate potential for rapidly propagating cracks and then develop and take corrective actions consistent with NRC Bulletin 88-02.	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Cast austenitic stainless steel reactor vessel internals (e.g., upper internals assembly, lower internal assembly, CEA shroud assemblies, control rod guide tube assembly, core support shield assembly, lower grid assembly) (3.1.1-80)	Loss of fracture toughness due to thermal aging and neutron irradiation embrittlement	Thermal Aging and Neutron Irradiation Embrittlement of CASS	No	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS)	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy or nickel alloy clad steam generator divider plate exposed to reactor coolant (3.1.1-81)	Cracking due to PWSCC	Water Chemistry	No	Water Chemistry Control – Primary and Secondary	Consistent with GALL Report
Stainless steel steam generator primary side divider plate exposed to reactor coolant (3.1.1-82)	Cracking due to SCC	Water Chemistry	No	Not applicable	Not applicable (see SER Section 3.1.2.1.1)
Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor vessel internals and reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-83)	Loss of material due to pitting and crevice corrosion	Water Chemistry	No	Water Chemistry Control – Primary and Secondary and Steam Generator Integrity (SG tubes)	Consistent with GALL Report
Nickel alloy steam generator components such as, secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater/steam (3.1.1-84)	Cracking due to SCC	Water Chemistry and One-Time Inspection or Inservice Inspection (IWB, IWC, and IWD).	No	Not applicable to IP2 Water Chemistry Control – Primary and Secondary and One-Time Inspection, and Steam Generator Integrity for IP3	Not applicable to IP2 (see SER Section 3.1.2.1.1) Consistent with GALL Report for IP3
Nickel alloy piping, piping components, and piping elements exposed to air - indoor uncontrolled (external) (3.1.1-85)	None	None	NA	None	Consistent with GALL Report

Component Group (GALL Report Item No.)	Aging Effect/ Mechanism	AMP in GALL Report	Further Evaluation in GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to air - indoor uncontrolled (External); air with borated water leakage; concrete; gas (3.1.1-86)	None	None	NA	None	Consistent with GALL Report
Steel piping, piping components, and piping elements in concrete (3.1.1-87)	None	None	NA	Not applicable	Not applicable (see SER Section 3.1.2.1.1)

The staff's review of the reactor vessel, reactor vessel internals, and reactor coolant system component groups followed any one of several approaches. In one approach, documented in SER Section 3.1.2.1, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. In the second approach, documented in SER Section 3.1.2.2, the staff reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. In the third approach, documented in SER Section 3.1.2.3, the staff reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the reactor vessel, reactor vessel internals, and reactor coolant system components is documented in SER Section 3.0.3.

3.1.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.1.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the reactor vessel, reactor vessel internals, and reactor coolant system components:

- Bolting Integrity Program
- Boric Acid Corrosion Prevention Program
- External Surfaces Monitoring Program
- Flux Thimble Tube Inspection Program
- Inservice Inspection Program
- Nickel Alloy Inspection Program
- One-Time Inspection - Small Bore Piping Program

- Reactor Head Closure Studs Program
- Reactor Vessel Head Penetration Inspection Program
- Reactor Vessel Surveillance Program
- Steam Generator Integrity Program
- Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program
- Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program
- Water Chemistry Control - Closed Cooling Water Program
- Water Chemistry Control - Primary and Secondary Program

LRA Tables 3.1.2-1-IP2 through 3.1.2-4-IP2 and 3.1.2-1-IP3 through 3.1.2-4-IP3 summarize the results of AMRs for the reactor vessel, reactor vessel internals, and reactor coolant system components and indicate AMRs claimed to be consistent with the GALL Report.

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report, where the report does not recommend further evaluation, the staff's audit and review determined whether the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.

For each AMR line item, the applicant stated how the information in the tables aligns with the information in the GALL Report. Notes A through E indicate how the AMR is consistent with the GALL Report. The staff audited these AMRs.

Note A indicates 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 GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates 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 GALL Report AMP. The staff audited these line items to verify consistency with the GALL Report and verified that the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified in the GALL Report a different component with the same material, environment, aging effect, and AMP as the component 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 indicates that the component for the AMR line item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. 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 and whether the identified exceptions to the GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

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

The staff audited and reviewed the information in the LRA. 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: (a) provided a brief description of the system, components, materials, and environments; (b) stated that the applicable aging effects were reviewed and evaluated in the GALL Report; and (c) identified those aging effects for the reactor vessel, reactor vessel internals, and reactor coolant system components that are subject to an AMR.

In response to RAI B.1.15-1, by letter dated January 4, 2008, the applicant revised the LRA to include an AMR line item for carbon steel blowdown pipe connection (nozzle) with an internal environment of treated water, an aging effect of "loss of material," and Note C. The staff reviewed the applicant's revision and found that the AMR result is consistent with the GALL Report for this combination of material, environment, and aging effect. On the basis of its review, the staff finds that all applicable aging effects were identified, and the aging effect listed is appropriate for the combination of material and environment identified.

On the basis of its audit and review, the staff determines that, for AMRs not requiring further evaluation, as identified in LRA Table 3.1.1, the applicant's references to the GALL Report are acceptable and no further staff review is required.

3.1.2.1.1 AMR Results Identified as Not Applicable

LRA Table 3.1.1, Line Items 38 – 51 discuss the applicant's determination on GALL AMR line items that are applicable only to BWR-designed reactors. In the applicant AMR discussions for these items, the applicant indicates that the AMR Line Items 38 – 51 in Table 1 of the GALL Report, Volume 1 are not applicable to the IP2 and IP3 LRAs because IP2 and IP3 are Westinghouse-designed PWRs. The staff verified that AMR Line Items 38 – 51 in Table 1 of the GALL Report, Volume 1 are only applicable to BWR designed reactors, and that IP2 and IP3 are 4-Loop Westinghouse-design PWRs with dry ambient containments. Based on this determination, the staff finds that the applicant has provided an acceptable basis for concluding

AMR Line Items 38 – 51 in Table 1 of the GALL Report, Volume 1 are not applicable to IP2 and IP3.

LRA Table 3.1.1, Line Item 54 addresses loss of material due to pitting, crevice, and galvanic corrosion of copper alloy piping, piping components, and piping elements exposed to closed cycle cooling water. The GALL Report recommends the closed-cycle cooling water system AMP to manage loss of material in these component groups. LRA Table 3.1.1, Line Item 56 addresses loss of material due to selective leaching in copper alloy >15 percent zinc piping, piping components, and piping elements exposed to closed cycle cooling water. The GALL Report recommends selective leaching of materials AMP to manage loss of material in these component groups. However, the LRA states that no copper alloy components exist in the Class 1 reactor vessel, vessel internals or reactor coolant pressure boundary and, therefore, these line items are not applicable. The staff verified from LRA Section 3.1.2.1 that there are no copper alloy components exposed to closed cycle cooling water at IP; therefore, the staff agrees that this line item is not applicable.

LRA Table 3.1.1, Line Item 75 addresses denting due to corrosion of carbon steel tube support plate in nickel alloy once-through steam generator (SG) tubes exposed to secondary feedwater/ steam. The GALL Report recommends steam generator tube integrity and water chemistry AMPs to manage denting in this component group. However, the LRA states that this line item applies to once through SGs, but IP2 and IP3 use recirculating SGs and, therefore, this line item is not applicable. The staff verified from LRA Section 2.3.1.4 that IP2 replaced its SGs in 2001 and IP3 replaced its SGs in 1989 with Westinghouse 44F recirculating models; therefore, the staff agrees that this line item is not applicable.

LRA Table 3.1.1, Line Item 77 addresses loss of material due to wastage and pitting corrosion in nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater/ steam. The GALL Report recommends steam generator tube integrity and water chemistry AMPs to manage loss of material in these component groups. However, the LRA states that the IP SGs are not exposed to phosphate chemistry in secondary feedwater or steam and, therefore, this line item is not applicable. The staff verified the water chemistry for secondary water during the audit and determined that IP does not use phosphate chemistry in its water chemistry control program for secondary water/steam. Therefore, the staff finds this acceptable.

LRA Table 3.1.1, Line Item 78 addresses wall thinning due to flow-accelerated corrosion in steel steam generator tube support lattice bars exposed to secondary feedwater/ steam. The GALL Report recommends steam generator tube integrity and water chemistry AMPs to manage wall thinning in these component groups. However, the LRA states that IP SGs do not employ tube support lattice bars and, therefore, this line item is not applicable. The staff verified from LRA Table 3.1.2-4-IP2 and 3.1.2-4-IP3 that IP SGs employ stainless steel tube support plates instead of lattice bar types support plates; therefore, the staff agrees that this line item is not applicable.

LRA Table 3.1.1, Line Item 79 addresses denting due to corrosion of steel tube support plate in nickel alloy steam generator tubes exposed to secondary feedwater/ steam. The GALL Report recommends steam generator tube integrity and water chemistry AMPs. For plants that could experience denting at the upper support plates, the GALL Report recommends that the potential for rapidly propagating cracks be evaluated, and for applicants to develop and take

applicable corrective actions consistent with staff's recommendations in NRC Bulletin 88-02. However, LRA states that IP SG tube support plates are made out of stainless steel and, therefore, this line item is not applicable. The staff verified from LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 that IP SGs employ stainless steel tube support plates instead of carbon steel support plates; therefore, the staff agrees that this line item is not applicable.

LRA Table 3.1.1, Line Item 82 addresses cracking due to SCC in stainless steel steam generator primary side divider plate exposed to reactor coolant. The GALL Report recommends water chemistry AMP to manage SCC in this component. However, the LRA states that the IP SG divider plates are made out of nickel alloy and, therefore, this line item is not applicable. The staff verified from LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 that the IP SGs employ nickel alloy channel head divider plates; therefore, the staff agrees that this line item is not applicable.

LRA Table 3.1.1, Line Item 84 addresses cracking due to SCC in nickel alloy SG components such as, secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater/ steam. The GALL Report recommends water chemistry and one time inspection or inservice inspection AMPs to manage SCC in this component. However, LRA Table 3.1.2-4-IP2 does not contain a similar entry for the IP2 SGs. The staff questioned the applicant in Audit Item 210 regarding this dissimilarity. In its response, dated December 18, 2007, the applicant stated that only IP3 has a nickel alloy RTD boss component; therefore, the staff finds this acceptable.

LRA Table 3.1.1, Line Item 87 addresses no aging effect in steel piping, piping components, and piping elements in concrete. The GALL Report recommends no aging management programs since there is no aging effect applicable to these components when buried in concrete. However, the LRA states that IP does not have components of the Class 1 reactor vessel, vessel internals or reactor coolant pressure boundary exposed to concrete and, therefore, this line item is not applicable. The staff confirmed during an audit that IP does not have any such components buried in concrete and, therefore, the staff finds this acceptable.

3.1.2.1.2 Cracking Due to Stress Corrosion Cracking, Loss Of Material Due to Wear, and Loss of Preload Due to Thermal Effects, Gasket Creep, and Self-Loosening of Bolting

LRA Table 3.1.1, Line Item 52 (LRA AMR 3.1.1-52) addresses cracking due to SCC, loss of material due to wear, and loss of preload due to thermal effects, gasket creep, and self-loosening of steel and stainless steel reactor coolant pressure boundary (RCPB) pump and valve closure bolting, manway and holding bolting, flange bolting, and closure bolting in high-pressure and high-temperature systems. The GALL Report recommends the bolting integrity AMP to manage these aging effects.

The GALL AMR that corresponds to LRA AMR 3.1.1-52 identifies that cracking due to SCC, loss of material due to wear, and loss of preload due to thermal effects, gasket creep, and self-loosening are applicable aging effects requiring management for steel and stainless steel reactor coolant pressure boundary (RCPB) pump and valve closure bolting, manway and holding bolting, flange bolting, and closure bolting in high-pressure and high-temperature systems.

The staff noted that the LRA indicated that GALL item is not applicable to IP2 and IP3 because the applicant did not consider cracking due to SCC, loss of preload due to stress relaxation, or

loss of material due to wear to be applicable AERM for the bolts used in the RCS bolted connections. In particular, the applicant indicated that cracking due to SCC is not an AERM for these bolts because the RCS bolts that were purchased and used under the applicant's QA program were of low to moderate tensile strengths. The applicant also indicated that its AMR process concluded that loss of material due to wear was not a significant aging effect and that loss of preload is an event driven condition.

The staff also noted that, since LRA AMR 3.1.1-52 did not identify any AERMs for the ASME Code Class 1 bolting in the reactor vessel, or RCS piping or steam generator designs, Tables 3.1.2-1-IP2, 3.1.2-1-IP3, 3.1.2-3-IP2, and 3.1.2-3-IP3 do not identify any applicable aging effects for the ASME Code Class 1 bolting used in RV and ASME Code Class 1 piping designs at IP2 and IP3.

For bolting components, the staff in Table IX.E of the GALL Report, Volume 2 identifies cracking and loss of preload as applicable potential aging effects for license renewal applications. Table IX.F of the GALL Report, Volume 2, identifies that SCC is an applicable mechanism that may lead to cracking of metallic components. Table IX.F of the GALL Report, Volume 2, indicates that wear is a mechanism that may lead to loss of material; that SCC is a mechanism that can lead to cracking; and that stress relaxation and thermal effects, gasket creep, and self-loosening are all potential aging mechanisms that may lead to loss of preload in bolted connections.

The staff did not accept the applicant's position that there are not any AERMs for the RCS bolting components because the applicant's position differed from the staff's recommendation in GALL AMRs IV.A2-6, IV.A2-7, IV.A2-8, IV.C2-7, IV.C2-8, IV.D1-2, and IV.D1-10, and from the aging effect/aging effect criteria for bolted assembly components in Tables IX.E and IX.F of the GALL Report, Volume 2. During an audit, the staff asked the applicant to clarify its position on the aging management of Class 1 bolting within the RCS (Audit Item 201).

The applicant provided the following response in a letter dated December 18, 2007, and amended LRA AMR 3.1.1-52 as follows:

> ~~Not applicable.~~
> High strength low alloy steel is not used for these bolting applications at IPEC. ~~Applied stress For stainless steel closure bolting applications should be much less than 100 ksi.~~ Consequently, cracking of bolting due to stress corrosion cracking is not an aging mechanism requiring management. Industry operating experience indicates that loss of material due to wear is not a significant aging effect for this bolting. Occasional thread failures due to wear related mechanisms, such as galling, are event driven conditions that are resolved as required. Loss of preload is a design driven effect and not an aging effect requiring management. Bolting at IPEC is standard grade B7 low alloy steel, or similar material, except in rare specialized applications such as where stainless steel bolting is utilized. Loss of preload due to stress relaxation (creep) would only be a concern in very high temperature applications (> 700 °F) as stated in the ASME Code, Section II, Part D, Table 4. No IPEC bolting operates at > 700 °F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for the reactor coolant system. Other issues that may result in pressure boundary joint leakage are improper design or maintenance

> issues. Improper bolting application (design) and maintenance issues are current plant operational concerns and not related to aging effects or mechanisms that require management during the period of extended operation. Nevertheless, the Bolting Integrity Program manages loss of preload for all external bolting in the reactor coolant system with the exception of the reactor vessel studs. As described in the Bolting Integrity Program, IPEC has taken actions to address NUREG-1339, *Resolution to Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants.* These actions include implementation of good bolting practices in accordance with EPRI NP-5067, "Good Bolting Practices." Proper joint preparation and make-up in accordance with industry standards is expected to preclude loss of preload. This has been confirmed by operating experience at IPEC.

The staff noted that SRP-LR Section A.1.2.1 provides the staff's position that leakage past a bolted connection is not to be treated as an abnormal event and that the aging effects leading to such leaking or resulting from such leakage need to be evaluated for the period of extended operation. This section of the SRP also states that:

> Specific aging effects from abnormal events need not be postulated for license renewal. However, if an abnormal event has occurred at a particular plant, its contribution to the aging effects on structures and components for license renewal should be considered for that plant. For example, if a resin intrusion has occurred in the reactor coolant system at a particular plant, the contribution of this resin intrusion event to aging should be considered for that plant.
>
> However, leakage from bolted connections should not be considered as abnormal events. Although bolted connections are not supposed to leak, experience shows that leaks do occur, and the leakage could cause corrosion. Thus, the aging effects from leakage of bolted connections should be evaluated for license renewal.

The staff reviewed the applicant's LRA AMR items relative to the applicable aging effects for SA-193, Grade B7 bolting components, as amended in the applicant's response to Audit Item 201. The staff noted that, with respect to the management of cracking due to SCC in the applicant's SA-193 Grade B7 bolts, the information in the LRA indicates that the cracking due to SCC would not be an aging effect requiring management (AERM) because the bolting components were procured to yield strengths less than 150 ksi (i.e. the applicant has indicated that the RCS bolts that were purchased and used under the applicant's QA program were of low to moderate tensile strengths, meaning the yield strengths for the materials are even lower. In the staff's safety evaluation on WCAP-14574-NP-A dated October 26, 2000, the staff provided its basis that cracking due to SCC does not need to be managed in SA-193 Grade B7 bolting materials if it was confirmed that the materials for the bolting components were procured to either yield strengths less than 150 ksi (considered high yield strengths) or to hardness values less than or equal to 32 on a Rockwell C Hardness scale. The staff finds that the applicant has provided an acceptable basis for concluding that cracking due to SCC is not an aging effect requiring management for these bolting components because it is consistent with the staff's basis in its SE on WCAP-14574-NP-A that cracking of SA-193, Grade B7 would not need to be managed if the materials for the bolting components were procured to either yield strengths less than 150 ksi or to hardness values less than or equal to 32 on a Rockwell C Hardness scale.

The staff noted, however, that the applicant's response to Audit Item 201 also indicated that loss of material due to wear and loss of preload due to stress relaxation were not aging effects and mechanisms that need to be managed in the SA 193, Grade B7 bolting components. However, in spite of this basis, the staff did note that the applicant's response to Audit Item 201 did indicate that these bolting components are included within the scope of the applicant's Bolting Integrity Program. Thus, the staff finds that by including the SA-193 Grade B7 bolting within the scope of the Bolting Integrity Program, the applicant will manage any loss of material, loss of preload, or potential cracking of the bolting that may occur during the period of extended operation. Audit Item 201 is resolved.

3.1.2.1.3 Cracking Due to Cycling Loading, Stress Corrosion Cracking, and Primary Water Stress Corrosion Cracking

LRA Table 3.1.1, Line Item 62 (LRA AMR 3.1.1-62) addresses cracking due to cyclic loading in stainless steel, steel with stainless steel cladding reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant. AMR Item 62 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-62) recommends an AMP corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," be credited to manage cracking due to cyclical loading in these components.

In LRA AMR 3.1.1-62, the applicant stated that GALL1 AMR 1-62 was not used because cracking due to cyclic loading is addressed in other LRA AMR items on cracking due to fatigue. In this AMR Item, the applicant also stated that in spite of this fact, the Inservice Inspection Program is credited to manage cracking of all ASME Code Class 1 stainless steel piping that is greater than four (4) inches in diameter (i.e., 4-inch NPS). Because the applicant did not use the GALL1 AMR item, the staff did not find any applicable AMRs in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3 on cracking in these large bore ASME Code Class 1 piping, piping components, or piping elements. In Audit Item 203, the staff asked the applicant to clarify its position on this component group.

The applicant responded to Audit Item 203 in a letter dated December 18, 2007. In this response, the applicant stated:

> Cracking due to cyclic loading is addressed in other items as cracking due to fatigue. The Inservice Inspection Program manages cracking of stainless steel piping > 4" nps.
>
> Table 3.1.2-3-1P2 and Table 3.1.2-3-1P3 line item "piping >4" nps / Treated borated water >140 deg F (int) / Cracking" is revised to add the following NUREG-1 801 Vol. 2 item, Table 1 item, and Note.
>
> IV.C2-26 (R-56) / 3.1.1-62 / E
>
> Information to be incorporated into the LRA.

The staff verified that the applicant made the stated changes to the LRA in the letter of December 18, 2007, and that the changes made to LRA AMR 3.1.1-62 are consistent with the position in GALL1 AMR 1-62. The staff also verified that, by the same letter, the applicant

amended the AMRs on cracking of large bore piping in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3 to be consistent with the AMR in GALL AMR Item IV.C2-26. Based on the applicant's response and the applicant's amendment of the LRA, the staff confirmed that the applicant amended its AMRs on cracking due to cyclical loading of the large bore ASME Code Class 1 piping at IP2 and IP3 to be consistent with the staff's position provided in the GALL Report recommending the Inservice Inspection Program be credited to manage cracking due to cyclical loading of these components. Based on the staff's review and confirmation of the appropriate amendments of the LRA, the staff finds that the applicant has proposed an acceptable basis for managing cracking due to cyclical loading in these large bore ASME Code Class 1 piping, piping components, and piping elements because the applicant's basis is consistent with the staff's position in the GALL Report.

LRA Table 3.1.1, Line Item 64 (LRA AMR 3.1.1-64) addresses cracking due to SCC or primary water stress corrosion cracking (PWSCC) in stainless steel and steel with stainless steel or nickel alloy cladding pressurizer components. The AMR that corresponds to LRA AMR 3.1.1-64 is AMR Item 64 in the GALL Report, Volume 1 (GALL1 AMR Table 1-64), This GALL AMR invokes GALL AMR IV.C2-19 and together these AMRs recommend that programs corresponding to GALL AMPs XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and XI.M2, "Water Chemistry," be credited to manage cracking in pressurizer components that are made from either stainless steel or steel with internal stainless steel or nickel alloy cladding.

The staff noted that the LRA indicated that the Water Chemistry Control Program – Primary and Secondary and Inservice Inspection Program are credited to manage cracking in steel with stainless steel or nickel alloy clad components and the management of cracking in the stainless steel components is addressed in other LRA Table 3.1.1 AMR items.

The staff asked the applicant to identify the additional pressurizer component AMRs that are used to manage cracking of the stainless steel pressurizer components or steel pressurizer components that are designed with internal stainless steel or nickel alloy cladding (Audit Item 204). In its response, dated December 18, 2007, the applicant stated that AMRs on cracking of the IP2 and IP3 pressurizer components are given in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3, respectively. The applicant also stated that these AMR items include those for the pressurizer heater sheaths, heater wells, manway insert plates, pressurizer penetrations, pressurizer spray heads, pressurizer spray head couplings and locking bars, thermal sleeves, and thermowells. The applicant further stated that the Table 1 rollup items for these components are Items 3.1.1-24, 3.1.1-68, or 3.1.1-70.

Regarding the applicant's response to the Table 2 AMR on cracking of the CASS pressurizer spray heads (as given in LRA Table 3.1.2-3-IP2 and 3.1.2-3-IP3), the staff noted that the applicant aligned the Table 2 AMR to LRA AMR Item 3.1.1-24. SER Section 3.1.2.2.7, Subsection (2) documents the staff's evaluation of the applicant's Table 2 AMR on cracking of the CASS pressurizer spray head.

Regarding the applicant's response to the Table 2 AMR on cracking of the IP2 pressurizer heater sheaths, heater wells, manway insert plates, pressurizer penetrations, pressurizer spray head couplings and locking bars, pressurizer thermal sleeves, and thermowells, the staff noted that the applicant aligned its Table 2 AMR items for these components to LRA AMR

Item 3.1.1-68. The staff's evaluation of the applicant's Table 2 AMR items for these components is documented later in this SER section.

The staff noted that the LRA did not include any AMRs on cracking of the steel pressurizer shell or head components (with internal stainless steel cladding) that aligned to GALL AMR IV.C2-19. Although the LRA did include some AMRs on cracking of the steel pressurizer shell courses and heads that are clad internally with stainless steel, the applicant aligned its AMRs on cracking of these pressurizer components to LRA AMR 3.1.1-67 and to GALL AMR IV.C2-18. These pertain to cracking in pressurizer components induced by cyclical loading (fatigue). The staff also noted that in these AMRs the applicant credited its Inservice Inspection Program to manage cracking in pressurizer components. This is the same program recommended in GALL AMR IV.C2-19 for managing cracking in the components if the cracking is induced by SCC or PWSCC. Thus, the staff concludes the alignment on cracking of these pressurizer shells and heads (including internal stainless steel cladding) to LRA AMR 3.1.1-67 and to GALL AMR IV.C2-18 adequately covers both alignment to LRA 3.1.1-67 and GALL AMR IV.C2-18 and to LRA AMR 3.1.1-64 and GALL AMR IV.C2-19. This is because the volumetric inservice inspections for these components would detect for cracking initiated by cyclical loading (fatigue) or by SCC or PWSCC. Therefore, the staff finds that the applicant has adequately addressed cracking in the steel pressurizer head and shells that are clad internally with stainless steel and are exposed to the reactor coolant.

The staff also noted that, in LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3, the applicant also aligned the following AMRs for steel RV components that are clad internally with stainless steel to GALL AMR IV.C2-19, including those for the RV closure heads, RV closure head flanges, RV shell flanges, RV inlet and outlet nozzles, RV closure head vents, RV upper shells, RV intermediate shells, RV lower shells, and associated welds. The staff noted that in these AMRs, the applicant credited its Water Chemistry Control Program – Primary and Secondary and Inservice Inspection Program for aging management of the components. The staff finds this to be acceptable because these RV components have the same material, environment, and aging effect combinations as those for the steel pressurizer components that are clad internally with stainless steel or nickel alloy materials and because the applicant's aging management basis for these RV components is consistent with the staff's recommended position in GALL AMR IV.C2-19.

LRA Table 3.1.1, Line Item 65 (LRA AMR 3.1.1-65) addresses cracking due to PWSCC in nickel alloy upper reactor vessel closure head (RVCH) control rod drive penetration nozzles, instrument tubes, head vent pipes (top head), and welds, and in the nickel alloy reactor vessel (RV) inlet and outlet nozzle safe-end welds. Item 65 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-65), which corresponds to LRA AMR 3.1.1-65, invokes GALL AMRs IV.A2-9 and IV.A2-18, as applicable to the management of cracking in control rod drive (CRD) penetration nozzles and upper RVCH head vent pipes and instrumentation tubes, and their associated nickel alloy nozzle-to-RV welds. Collectively, these GALL-based AMRs all recommend that programs corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurizer Water Reactors," manage cracking in these nickel alloy nozzle components and their associated nickel alloy nozzle-to-RV penetration welds.

The staff noted that in LRA AMR Item 3.1.1-65, the applicant credited only its Water Chemistry Control Program – Primary and Secondary (LRA AMP B.1.41) and the Nickel Alloy Inspection Program (LRA AMP B.1.21) to manage cracking in the nickel alloy upper RVCH penetration nozzles or any upper RVCH nozzles that are welded to the upper RVCH using nickel alloy nozzle-to-RV penetration welds, and in the nickel alloy RV inlet and outlet nozzle safe-end welds. The staff had two issues with this aging management basis: (1) the applicant did not credit its Inservice Inspection Program, as is otherwise recommended in the applicable GALL AMRs, and (2) in LRA AMR. 3.1.1-65, the applicant credited its general nickel alloy aging management program for the upper RVCH penetration nozzle and its associated nickel alloy nozzle-to-RV welds. The staff addressed these issues in Audit Item 205.

In its response dated December 18, 2007, the applicant amended AMR line items in LRA Table 3.1.2-1-IP2 and LRA Table 3.1.2-1-IP3 to add the applicant's Inservice Inspection Program to the Water Chemistry Program and the Nickel Alloy Inspection Program as the basis for managing cracking due to PWSCC. The staff noted that the applicable components included the upper RVCH head vent safe end and their associated welds and the nickel alloy RV inlet and outlet nozzle safe-end welds. The staff noted that addition of the Inservice Inspection Program will make the AMRs for these penetration nozzles consistent with the staff's recommended AMR guidance in GALL1 AMR 1-65.

With respect to aging management of cracking in nickel alloy RV inlet and outlet nozzle safe-end welds, the staff's basis in GALL AMR IV.A2-15 recommends Inservice Inspection Programs be credited for aging management. This is because the RV inlet and outlet nozzle safe end welds are ASME Code Class 1 full penetration butt welds that are required to be inspected by volumetric inspection techniques once every 10-year ISI Interval. These volumetric examinations are also required to be subject the NRC's performance demonstration initiative requirements (PDI) that are defined and required in 10 CFR 50.55a. Thus, the staff found that the applicant's response to Audit Item 205 and LRA amendment of the Table 2 AMR entry on cracking of the nickel alloy RV inlet and outlet nozzle safe-end welds resolved the staff's issue with respect to these components. This is because the addition of the Inservice Inspection Program as an added basis for aging management makes the AMR entry for these components consistent with the staff aging management recommendations in IV.A2-15, with the added conservatism that the Nickel Alloy Inspection Program is also credited for aging management of cracking in these nickel alloy components.

The staff determined that the applicant's response to Audit Item 205 and the LRA amendment provided in the December 18, 2007, letter did not resolve the issue with respect to the AMPs that should be credited for aging management of cracking in the upper RVCH penetration nozzles. The staff's basis for this finding is as follows: GALL1 AMR 1-65, and GALL AMRs IV.A2-9 and IV.A2-18, which derive from this GALL1 AMR, deal only with management of cracking due to PWSCC in nickel alloy upper RVCH penetration nozzles in PWRs (including CRD penetration nozzles, and upper RVCH head vent and instrumentation nozzles), and their associated nickel alloy nozzle-to-RV welds.[7] These GALL AMRs recommend that programs that

[7] GALL1 AMR 1-65, and GALL AMRs IV.A2-9 and IV.A2-18 are only applicable to CRD penetration nozzles and upper RV head vent nozzles and their nickel alloy welds and are not applicable to CRD pressure housings. The GALL AMRs on cracking of CRD pressure housings is addressed in AMR Item 34 of Table 1 to the GALL Report, Volume 1 (GALL1 AMR 1-34), and in GALL AMR IV.A2-11 which is derived from this GALL1 AMR. The GALL AMRs on cracking of RV inlet and outlet nozzles safe ends and safe end welds is addressed in AMR Item 69 of Table 1 to the GALL Report, Volume 1 (GALL1 AMR 1-69), and in GALL AMR IV.A2-15 which is derived from this GALL1 AMR.

correspond to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors," be credited to manage cracking due to PWSCC in these upper RVCH nickel alloy components. In contrast, the applicant's AMR entry in LRA 3.1.1-65 for any upper RVCH nozzles made from nickel alloy base metals and are welded to the upper RVCH using nickel alloy nozzle-to-RV welds or for any non-nickel alloy RVCH nozzles that are welded to the upper RVCH using nickel alloy nozzle-to-RV welds, in part, credited AMP B.1.21, Nickel Alloy Inspection Program. In addition, B.1.31, Reactor Vessel Head Penetration Inspection Program and GALL AMP XI.M11A are based on compliance with the staff's augmented inspection requirements for PWR upper RVCH penetration nozzles, as issued in NRC Order EA-03-009, and amended in the First Revised Order EA-03-009 (henceforth referred to as the "Order as Amended"). Thus, the applicant's entry in LRA AMR 3.1.1-65 should specify that AMP B.1.31, Reactor Vessel Head Penetration Inspection Program is credited for aging management, because that is the applicant's nickel alloy management program that corresponds to GALL AMP XI.M11A, "Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors (PWRs Only)," and not AMP B.1.21, Nickel Alloy Inspection Program, which is not based on compliance with the Order as Amended.[8]

The staff reviewed LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 to see if the applicant's Table 2 AMRs on cracking of the upper RVCH nozzles appropriately credited the proper AMPs recommended in GALL AMRs IV.A2-9 and IV.A2-18. The staff noted that the applicant includes only one AMR entry each in LRA Table 3.1.2-1-IP2 and Table 3.1.2-1-IP3 for its nickel alloy RVCH penetration nozzles (which is the AMR entry for the CRD head penetration housing tubes [nozzles]) and that in this Table 2 AMR item entry, the applicant appropriately credited its Reactor Vessel Head Penetration Inspection Program, along with the Water Chemistry Control Program – Primary and Secondary and the Inservice Inspection Program, to manage cracking of the components. However, the staff also noted that the applicant inappropriately aligned this Table 2 AMR item to LRA AMR 3.1.1-34 which is for CRD pressure housings, and not to LRA 3.1.1-65, which is the appropriate Table 1 AMR for CRD penetration nozzles and upper RVCH head vent and instrumentation nozzles. The staff also noted that the applicant's Table 2 AMRs in LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 did include an entry on cracking of the upper RVCH head vent nozzles and that in these AMR items, the applicant identified that the upper RVCH head vent nozzle was made of carbon steel with stainless steel cladding. However, the staff noted that the AMRs entries on the upper RVCH head vent nozzles did not clarify whether the head vent nozzle-to-RV weld for the upper RVCH head vent nozzles were made of nickel alloy filler weld material. Thus, the staff determined that the application's AMR inputs for the upper RVCH penetration nozzles and CRD pressure housings needed additional information and clarification.

In a letter dated December 30, 2008, the staff issued RAI 3.1.2-1, Part A to resolve these issues. This was identified as part of Open Item 3.1.2-1.

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[8] For the Table 2 AMR entries on cracking in LRA Table 3.1.2-1-IP2 and 3.1.2-1-IP3 for the CRD penetration housing tubes (i.e., the CRD penetration nozzles), the staff noted that the applicant appropriately credited, in part, LRA AMP B.1.31, Reactor Vessel Head Penetration Inspection Program for aging management. Thus, the issue is with the general AMR basis discussed in LRA AMR 3.1.1-65 for upper RVCH penetrations, and with a question on whether the upper RVCH vent nozzles and any upper RVCH instrumentation nozzles are welded to the upper RVCHs using nickel alloy nozzle-to-RV welds.

The applicant responded to RAI 3.1.2-1 in a letter dated January 27, 2009. In this response, the applicant clarified that the CETNA nozzles used in the upper RV head designs are fabricated from stainless steel and do not include any nickel alloy base metal or weld materials. Instead, the applicant clarified that the CETNA assemblies are fabricated as follows:

"A CET head port adapter is connected to the penetration housing adapter flange, and then connected to the CETNA assembly via a conoseal joint. All CETNA assemblies are sealed to the CET columns with Grafoil seals using a compression collar and a hold down nut with no welds. As shown in the LRA Tables, the CETNA are constructed from stainless steel."

Based on this supplemental information, the applicant has provided an acceptable basis for concluding that the CETNA assemblies do not need to be within the scope of and managed by the Nickel Alloy Inspection Program because these components do not include any nickel alloy base metal or weld components.

In the applicant's response to RAI 3.1.2-1, the applicant also clarified that the only nickel alloy welds associated with the upper RVCH vent nozzles are those nickel alloy welds that join these nozzles to the nickel alloy closure head vent nozzle safe-end. The applicant explained the vent nozzles are carbon steel nozzles with internal stainless steel cladding that are welded to the carbon steel upper RVCH using carbon steel weld materials that have been post weld heat treated. The applicant clarified that the nickel alloy welds associated with the nickel alloy vent nozzle safe ends are within the scope of the applicant's Nickel Alloy Inspection Program. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the upper RVCH head vent nozzle-to-upper RVCH welds do not need to be managed by or be within the scope of the either the Nickel Alloy Inspection Program or Reactor Vessel Head Penetration Inspection Program because these components and their associated welds are not fabricated from nickel alloy materials.

Based on this review, the staff finds that the applicant has provided an acceptable basis for managing cracking in these upper RVCH head vent nozzles and CETNA nozzles because: (1) the applicant has clarified which of nozzle designs include nickel alloy base metal or weld materials, (2) the applicant has appropriately credited its Nickel Alloy Inspection Program and Water Chemistry Program to manage cracking in the nickel alloy upper RVCH head vent nozzle safe ends and their nickel alloy safe-end-to-nozzle welds, and (3) in the applicant's AMRs for the CETNA nozzles and upper RVCH head vent nozzles, as given in LRA Tables 3.1.2-IP2-1 and 3.1.2-IP3, the applicant has appropriately credited its Water Chemistry Program and Inservice Inspection Program for any cracking that may develop in the components. RAI 3.1.2-1 is resolved and Open Item 3.1.2-1 is closed with respect to the management of cracking in the upper RVCH head vent nozzles and the CETNA nozzles.

LRA Table 3.1.1, Line Item 69 (LRA AMR Item 3.1.1-69) addresses cracking due to SCC and PWSCC in stainless steel and nickel alloy safety injection nozzles, safe ends, and associated welds and buttering exposed to reactor coolant. AMR Item 69 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-69) is the GALL AMR that corresponds to LRA AMR 3.1.1-69. In this GALL1 AMR, and in GALL AMR IV.A2-15, the staff recommends that AMPs corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD," and GALL AMP XI.M2, "Water Chemistry," be credited to manage cracking in these components under exposure to the reactor coolant.

The staff verified that, in LRA Table 3.1.2-1-IP2, the applicant includes two AMRs that aligned to GALL AMR IV.A2-15: (1) cracking of the stainless steel reactor vessel (RV) inlet and outlet nozzle safe-ends, and (2) cracking of the stainless steel RV bottom head safe-ends and safe-end welds. In these AMRs, the staff noted that the applicant credited its Water Chemistry Control Program – Primary and Secondary and its Inservice Inspection Program to manage cracking in the stainless steel component surfaces that are exposed to the reactor coolant. This is in conformance with the recommendation in GALL AMR IV.A2-15, that AMPs corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD," and GALL AMP XI.M2, "Water Chemistry," be credited to manage cracking in stainless steel RV inlet nozzle, outlet nozzle and safety injection nozzle safe end components and their associated nickel alloy safe-end welds.

In Audit Item 208, the staff asked the following question:

> In LRA Table 3.1.1, Item 3.1.1-69, Entergy states, The Water Chemistry Control - Primary and Secondary and Inservice Inspection Programs manage cracking in stainless steel nozzles and penetrations. Nickel alloy used for such applications is compared to other lines. Identify which other lines applicable to Ni-alloy components exposed to reactor coolant and manage cracking due to SCC and PWSCC.

In its response, dated December 18, 2007, the applicant stated the LRA AMR 3.1.1-69 is a rollup only for the stainless steel RV inlet and outlet nozzle safe-ends and the safe ends and safe-end welds on the bottom head drains. The applicant stated that the LRA Tables 3.1.2-1-IP2 through 3.1.2-4-IP2 and LRA Tables 3.1.2-1-IP3 through 3.1.2-4-IP3 include numerous AMR items for nickel alloy components. Examples are the control rod drive penetrations, the RV inlet/outlet nozzle safe end welds, and the bottom head instrument penetrations. The applicant stated that these AMR items are compared to Items IV.A2-18 and IV.A2-19, which roll up to table entries 3.1.1-31 and 3.1.1-65. The applicant stated that the AMR in LRA AMR 3.1.1-69 is only for management of cracking in the RV inlet and outlet nozzle safe-ends and the RV bottom head drain safe-ends.

The staff reviewed LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 to determine whether the information in the applicant's response to Audit Item 208 was valid with respect to the applicant's basis for managing cracking due to SCC or PWSCC in the nickel alloy components associated with the RV bottom heads. The staff noted that, in the applicant's response to Audit Item 208, the applicant mentioned that the nickel alloy components in the RV bottom heads, which align to LRA AMR 3.1.1-69, are the nickel alloy safe-ends for the RV bottom head drains. However, the staff also noted that LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 do not include any AMR entries for RV bottom head drains or specifically for nickel alloy bottom head drain safe ends and welds. Thus, the staff determined that the applicant would need to better define which of the components and welds associated with the RV bottom heads are made from nickel alloy materials and what the applicant's basis is for managing cracking due to SCC or PWSCC in these nickel alloy RV bottom head components and welds. By letter dated December 30, 2008, the staff issued RAI 3.1.2-1, Part B to resolve this issue. The staff's acceptance of LRA AMR 3.1.1-69 is pending acceptable resolution of RAI 3.1.2-1, Part B on aging management of nickel alloy components that are associated with the RV bottom heads or their penetration nozzles. This was identified as part of Open Item 3.1.2-1.

By letter dated January 27, 2009, the applicant responded to RAI 3.1.2-1, Part B. In this response, the applicant clarified that neither the IP2 nor IP3 reactor vessels have bottom head drains, and that the response to Audit Item 208 should have referred to the nickel alloy welds in bottom head safe ends instead of the bottom head drain safe end welds. The staff noted that the clarification made in the response to RAI 3.1.2-1, Part B is consistent with the actual design of the RV bottom head nozzle at IP2 and IP3. The staff finds this response provides an acceptable basis for resolving which components in RV bottom heads are fabricated with nickel alloy welds because the clarification is consistent with the actual design of IP2 and IP3 RV bottom heads. The staff confirmed that the LRA indicates that the applicant is crediting its Water Chemistry Control Program, the Inservice Inspection Program, and the Nickel Alloy Inspection Program to manage cracking due to PWSCC in the RV bottom head instrumentation nozzles and their nickel alloy safe end welds. This is consistent with the AMPs recommended for aging management in GALL AMR Item IV.A2-19. RAI 3.1.2-1, Part B is resolved and Open Item 3.1.2-1 is closed with respect to identifying which of the RV bottom head components and associated welds are fabricated from nickel alloy materials.

In LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3, the applicant includes AMRs on cracking of the stainless steel regenerative heat exchanger bonnet, shell, and tube surfaces that are exposed to borated treated water (i.e. to the reactor coolant). The applicant aligned these AMRs to LRA Table 3.3.1, AMR item 3.3.1-8, which states "Stainless steel components of some heat exchangers to which this NUREG-1801 line item applies, including the regenerative heat exchanger, are in the reactor coolant systems in series 3.1.2-x tables." SER Section 3.3.2.2.4, Item (2) documents the staff's evaluation of these AMRs.

LRA Table 3.1.1, Line Item 68 (LRA AMR 3.1.1-68) addresses cracking due to SCC in Class 1 piping, fittings, pump casings valve bodies, nozzles, safe ends, manways, flanges, CRD housing; pressurizer heater sheaths, sleeves, diaphragm plate; pressurizer relief tank components; reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings that are made from either stainless steel or steel with internal stainless steel cladding. AMR Item 68 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-68) is the GALL AMR that corresponds to LRA AMR 3.1.1-68. In this GALL1 AMR, and in GALL AMRs IV.C2-2, IV.C2-5, IV.C2-20, IV.C2-22, IV.C2-27, and IV.D1-1 which are invoked by this GALL1 AMR, the staff recommends that AMPs corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and GALL AMP XI.M2, "Water Chemistry," be credited to manage cracking in these components.

The staff noted that in the LRA, the applicant credited its Water Chemistry Control Program – Primary and Secondary and its Inservice Inspection Program to manage cracking in all ASME Code Class 1 reactor coolant pressure boundary components that are subject to inservice inspections. This includes the stainless steel (including CASS) ASME Code Class 1 large bore (≥ 4-inch NPS) piping, piping components, piping elements; pump casings; large bore (≥ 4-inch NPS) valve bodies, pressurizer penetration nozzles, pressurizer manway inserts, pressurizer heater sheaths and wells, and pressurizer thermal sleeves; SG primary manways, and SG primary nozzles. The staff finds that the applicant's aging management basis for managing cracking in these components is acceptable because the crediting of the Water Chemistry Control Program – Primary and Secondary and the inservice Inspection Program is consistent with the programs recommended for aging management in GALL1 AMR 1-68 and GALL AMRs IV.C2-2, IV.C2-5, IV.C2-20 and IV.D1-1.

For the non-ASME Code Class 1 (non-pressure boundary) stainless steel components in the RCS, including the pressure spray head couplings and locking bars and the primary SG manway cover inserts, the applicant credited only its Water Chemistry Control Program – Primary and Secondary to manage cracking in the components.

The staff noted that the applicant did not credit an inspection-based program to verify the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing cracking of these stainless steel non-ASME Code Class 1 (non-pressure boundary) components. In Audit Item 207, the staff asked the applicant to justify its basis for crediting only the Water Chemistry Control Program – Primary and Secondary for management of cracking in the pressurizer spray head couplings and locking bars, and for not crediting a One Time Inspection to verify the effectiveness of Water Chemistry Control Program – Primary and Secondary in managing this aging effect. In Audit Item 357, the staff asked the applicant to justify its basis for crediting only the Water Chemistry Control Program – Primary and Secondary as the basis for managing cracking in the SG primary manway cover inserts and why the Inservice Inspection Program had not been credited for cracking in these components.

In its response to Audit Items 207 dated December 18, 2007, the applicant clarified that the pressurizer spray head couplings and locking bars are not AMSE Code Class components and, therefore, these couplings and locking bars are not within the scope of the applicant's Inservice Inspection Plan. The applicant clarified that a One Time Inspection will be used to verify the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing cracking of the pressurizer spray head couplings and locking bars as a result of SCC.

In its response to Audit Item 357 dated December 18, 2007, the applicant clarified that the primary SG manway cover inserts are ASME Code Class 1 components and that these components are within the scope of the applicant's Inservice Inspection Program. As a result, the applicant stated that it is crediting both the Water Chemistry Control Program – Primary and Secondary and the Inservice Inspection Program to manage cracking of the primary SG manway inserts and that the applicable Table 2 AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 for the primary SG manway insert would be amended accordingly.

With respect to the applicant's response to Audit Item 357, the staff verified that the applicant made the appropriate changes to the AMRs on cracking of the primary SG manway cover inserts in the LRA amendment dated December 18, 2007. The staff also verified that this change makes the AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 for the primary SG manway cover inserts consistent with the aging management guidance in GALL1 AMR 1-68 and GALL AMR IV.D1-1. Based on this LRA amendment the staff finds that the applicant's AMRs on cracking of the primary SG manway cover inserts are acceptable because the applicant's amended AMRs for the components have been verified as being consistent with staff's recommended aging management position that is provided in GALL AMR IV.D1-1. The staff also confirmed that, in the applicant's AMRs in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3 on cracking of ASME Code Class 1 piping and pressurizer components, in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 on cracking of ASME Code Class 1 SG components, the applicant has provided an acceptable basis for crediting the Water Chemistry Control Program – Primary and Secondary and the Inservice Inspection Program to manage cracking of the components under exposure to the reactor coolant. Based on the review, the staff finds that the applicant's AMRs for these components are acceptable because they are consistent with the recommended

guidance in GALL1 AMR 1-68 and in GALL AMR IV.C2-2, IV.C2-5, IV.C2-20 or IV.D1-1. Audit Item 357 is resolved.

With respect to the applicant's response to Audit Item 207 on aging management of cracking due to SCC of the pressurizer spray head couplings and locking bars, the staff concludes that the applicant has provided an acceptable basis for crediting the Water Chemistry Control Program – Primary and Secondary and the One-Time Inspection Program to manage cracking in the pressurizer spray head coupling and locking bars because the components are not categorized as ASME Code Class 1 components and because, consistent with the staff's guidance in GALL AMP XI.M32, "One-Time Inspection," the One Time Inspection Program will be used to verify that the Water Chemistry Control Program – Primary and Secondary is effective in managing cracking of these components as a result of SCC. Audit Item 207 is resolved.

3.1.2.1.4 Cracking Due to Stress Corrosion Cracking and Loss of Material Due to Crevice Corrosion and Fretting

LRA Table 3.1.1, Line Item 74 (LRA AMR 3.1.1-74) addresses cracking due to SCC and loss of material due to crevice corrosion and fretting in chrome plated steel, stainless steel, nickel alloy SG anti-vibration bars exposed to secondary feedwater/steam.

GALL AMR IV.D1-15 pertains to the management of loss of material due to crevice corrosion or fretting in carbon steel SG antivibration bars in PWRs with recirculating SGs. In this AMR, the staff recommends that programs corresponding to GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M19, "Steam Generator Tube Integrity," be credited for aging management of loss of material due to crevice corrosion or fretting in chrome plate steel, stainless steel, or nickel alloy component surfaces that are exposed to secondary treated water or steam environments (i.e., to FW or steam).

The staff noted that for anti-vibration bars and end caps, peripheral retaining rings, feedwater (FW) nozzle thermal sleeves, the applicant credited both its Water Chemistry Control Program – Primary and Secondary Program and its Steam Generator Integrity Program for aging management of loss of material in the component surfaces that are exposed to either a treated water or steam environment, which is consistent with the recommendations in GALL AMR IV.D1-15. SER Sections 3.0.3.2.17 and 3.0.3.2.14 document the staff's evaluation of the Water Chemistry Control Program – Primary and Secondary Program and the Steam Generator Integrity Program, respectively.

3.1.2.1.5 Wall Thinning Due to Flow-Accelerated Corrosion

LRA Table 3.1.1, Line Item 59 (LRA AMR 3.1.1-59) addresses wall thinning due to flow-accelerated corrosion in steel SG steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam. AMR Item 59 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-59) is the AMR that corresponds to LRA AMR 3.1.1-59. For PWRs with recirculating SGs (like IP2 and IP3), AMR IV.D1-5 is the component specific AMR that derives from GALL1 AMR 1-59. In these AMRs, the staff recommends that an AMP corresponding to GALL AMP XI.M17, "Flow-Accelerated Corrosion," be credited to manage wall thinning in these components as a result of flow-accelerated corrosion.

In LRA AMR 3.1.1-59, the applicant stated that the SG steam outlet nozzle contains a nickel alloy flow restrictor and the SG feedwater (FW) nozzle contains a nickel alloy thermal sleeve that isolate the carbon steel nozzles from high fluid velocities. Based on these design features, the applicant concluded that these components are not susceptible to flow-accelerated corrosion. However, during the audit, the staff found that a small section of the SG FW nozzle next to the FW piping is exposed to FW flow and is, therefore, susceptible to flow-accelerated corrosion requiring aging management. The staff asked why the design features for these SG nozzles would be sufficient to mitigate the potential for flow-accelerated corrosion to initiate in the component surfaces that are exposed to the feedwater or steam environments (Audit Item 202). Specifically, the staff asked the applicant to explain: (1) why the flow restrictor for the nickel alloy SG steam outlet nozzle is considered to be sufficient for isolating the SG outlet nozzles and their safe-ends from a two-phase steam environment (i.e., steam with some water content in it), and (2) why the thermal sleeves for the SG FW and auxiliary feedwater (AFW) nozzles are considered to be sufficient for isolating these SG nozzles and their safe-end from the secondary treated water environment,

The applicant responded to Audit Item 202 in a letter dated December 18, 2007. With respect to the SG steam outlet nozzles, the applicant clarified that the flow restrictors for the SG outlet nozzles totally isolate the components from exposure to a two-phase steam environment. In addition, the applicant clarified that, even if the carbon steel nozzles were exposed to the steam environment, flow-accelerated corrosion would not be an aging mechanism of concern because the steam environment would be of a high quality (i.e., dry). In GALL AMP XI.M17, "Flow-Accelerated Corrosion," the staff endorses EPRI Report NSAC-202, Revision 2 as an acceptable basis for identifying whether carbon steel or alloy steel materials are susceptible to flow-accelerated corrosion. In this document, the industry identifies that carbon steel or alloy steel materials with less than 0.75 percent chromium contents are susceptible to flow-accelerated corrosion if they are subjected to high velocity aqueous environments (i.e. high velocity water-based solutions) or high velocity water/steam environments (i.e. high velocity two-phased aqueous flow environments). The staff's finds this to be an acceptable response because the steam environment coming off the SG steam dryers are essentially 99.9 percent dry steam and this environment does not have a sufficient water content to be considered a high velocity two-phase aqueous environment. As a result, the staff finds that the applicant has provided an acceptable basis for concluding that loss of material due to flow-accelerated corrosion is not an AERM in the SG steam outlet nozzles or their safe-ends. Audit Item 202 is resolved with respect to the SG steam outlet nozzles and the safe-ends.

With respect to the AFW nozzles, the applicant clarified, in a letter dated December 18, 2007, that the AFW system is not normally in service and that, as a result of this operational basis, loss of material due to flow-accelerated corrosion is not an AERM for the period of extended operation. The staff noted that the SRP-LR Section A.1.2.1, Item 7, provides the following discussion about using an operational consideration as a basis for identifying whether an aging effect is applicable to a specific component:

> The applicable aging effects to be considered for license renewal include those that could result from normal plant operation, including plant/system operating transients and plant shutdown. Specific aging effects from abnormal events need not be postulated for license renewal. However, if an abnormal event has occurred at a particular plant, its contribution to the aging effects on structures

and components for license renewal should be considered for that plant. For example, if a resin intrusion has occurred in the reactor coolant system at a particular plant, the contribution of this resin intrusion event to aging should be considered for that plant.

For PWR designs, AFW systems are initiated only during anticipating operational transients that result in a SCRAM of the reactor, during postulated design basis accidents, or during initiations of the systems that are implemented to meet required technical specification (TS) surveillance requirements. Thus, the staff finds that the applicant's basis for concluding that loss of material due to flow-accelerated corrosion is not an AERM for the SG AFW nozzles is acceptable because it is in conformance with the position in SRP-LR Section A.1.2.1, Item 7, that specific aging effects from abnormal events need not be postulated for license renewal. Audit Item 202 is resolved with respect to the SG AFW nozzles.

With respect to the SG FW nozzles and safe-ends, the applicant clarified, in a letter dated December 18, 2007, that, upon further review, the design of the carbon steel SG FW nozzles includes a portion of the nozzles (next to the FW piping) that is exposed to the FW treated water environment. To address this issue, the applicant stated that the LRA would be amended to include new AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 on loss of material due to flow-accelerated corrosion for the SG FW nozzles that are exposed to treated water. In addition, in the AMRs consistent with the staff's aging management basis in GALL AMR IV.D2-7 (which provides equivalent aging management basis to the staff's aging management basis in GALL AMR IV.D1-5), the applicant will credit the Flow-Accelerated Corrosion Program with the management of this aging effect/aging mechanism.

The staff verified that the applicant made the applicable amendments of the LRA in the letter of December 18, 2007. The staff also verified that the applicant's amended AMR basis for managing loss of material due to flow-accelerated corrosion in the SG FW nozzle components is consistent with the staff's basis for managing loss of material due to flow-accelerated corrosion in SG FW nozzles, as given in either GALL AMR IV.D1-5 or GALL AMR IV.D2-7. Based on this amendment of the LRA, the staff finds the applicant has provided an acceptable basis for managing loss of material due to flow-accelerated corrosion in the IP2 and IP3 SG FW nozzles. This is because, consistent with the staff's aging management basis in GALL AMR IV.D1-5 or IV.D2-7, the applicant has identified that loss of material due to flow-accelerated corrosion is an AERM for the SG FW nozzles, and because the applicant has credited its Flow-Accelerated Corrosion Program to manage loss of material due flow-accelerated corrosion in these components. Audit Item 202 is resolved with respect to the SG FW nozzles.

3.1.2.1.6 Loss of Material Due to Erosion

LRA Table 3.1.1, Line Item 66 (LRA AMR 3.1.1-66) addresses loss of material due to erosion in steel steam generator secondary manways and handholds (cover only) exposed to air with leaking secondary-side water and/or steam. AMR Item 66 in Table 1 of the GALL Report, Volume 1 (GALL1 AMR 1-66), and GALL AMR IV.D2-5 recommend that an AMP corresponding to GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," be credited to manage loss of material in the secondary manways and handholds (cover only) of once-through SG designs.

The staff noted that in LRA AMR 3.1.1-66, the applicant stated that GALL1 AMR 1-66 was not used, since erosion at manways and handholes is the result of leaking joints that have not been corrected. The applicant clarified in the application that leaks at IP2 and IP3 are repaired as soon as practical, and that if damage due to erosion occurred, it would also be repaired. In Audit Item 206, the staff asked the applicant to provide further clarification on its basis for concluding that loss of material due to erosion is not an aging effect requiring management for the SG secondary manways and handhold.

By letter dated December 18, 2007, the applicant provided the following response to the staff's question:

> Erosion at manways and handholes results from abnormal conditions, that is, leakage. This mechanism can cause loss of material independent of the age of the components. Pressure leak tests are required by ASME Section XI, IWC. Because ISI of secondary components manages potential leaks, erosion of manways and handholes due to leakage is not an applicable aging effect.

The staff noted that the applicant used an argument that leakage past the bolted connections in the secondary SG manway and handhold covers is an abnormal event, and that because of this fact, loss of material due to erosion does not need to be identified as an AERM for these components. In Section A.1.2.1, Item 7 of the Appendix A of the SRP-LR (i.e., NUREG-1800, Revision 1), the staff takes the following position on whether correction of leakage from in-scope components can be used as a basis for concluding that a specific aging effect is not applicable and does not need to be managed:

> The applicable aging effects to be considered for license renewal include those that could result from normal plant operation, including plant/system operating transients and plant shutdown. Specific aging effects from abnormal events need not be postulated for license renewal. However, if an abnormal event has occurred at a particular plant, its contribution to the aging effects on structures and components for license renewal should be considered for that plant. For example, if a resin intrusion has occurred in the reactor coolant system at a particular plant, the contribution of this resin intrusion event to aging should be considered for that plant.
>
> [Design basis events] DBEs are abnormal events; they include: design basis pipe break, LOCA, and safe shutdown earthquake (SSE). Potential degradations resulting from DBEs are addressed, as appropriate, as part of the plant's CLB. There are other abnormal events which should be considered on a case-by-case basis. For example, abuse due to human activity is an abnormal event; aging effects from such abuse need not be postulated for license renewal. When a safety-significant piece of equipment is accidentally damaged by a licensee, the licensee is required to take immediate corrective action under existing procedures (see 10 CFR Part 50 Appendix B) to ensure functionality of the equipment. The equipment degradation is not due to aging; corrective action is not necessary solely for the period of extended operation.

> However, leakage from bolted connections should not be considered as abnormal events. Although bolted connections are not supposed to leak, experience shows that leaks do occur, and the leakage could cause corrosion. Thus, the aging effects from leakage of bolted connections should be evaluated for license renewal.

The staff noted that the applicant's response to Audit Item 206 was inconsistent with NRC's position in the SRP-LR that "leakage from bolted connections should not be considered as abnormal events," and that "the aging effects from leakage of bolted connections should be evaluated for license renewal." Thus, the staff would normally take the position that the applicant's position should be consistent with the staff's aging effect identification criterion in Section A.1.2.1, Item 7 of the Appendix A of the SRP-LR (i.e., NUREG-1800, Revision 1), and that leakage past the SG secondary manway bolting should be assessed for aging effects that could impact the integrity of the manway covers or their bolts. However, the staff did note that the applicant's response to Audit item 201 did indicate that the SA-193, Grade B7 bolting at IP2 and IP3 is included within the scope of the applicant's Bolting Integrity Program. Thus, the staff finds that by including the SA-193 Grade B7 bolting within the scope of the Bolting Integrity Program, the applicant will manage any loss of material, loss of preload, or potential cracking of the bolting that may occur during the period of extended operation. Thus, the staff was of the opinion that the applicant's response to Audit Item 201 was an extension of the applicant's response to Audit Item 206 and that any aging of the manway and handhole cover would be adequately managed because the applicant's implementation of its Bolting Integrity Program would be sufficient to manage any cracking, loss of material, or loss of preload that would occur in the SG secondary manway and handhole cover bolted connections. Audit Item 206 is resolved after taking into account that the information in the applicant's response to Audit Item 201, dated December 18, 2007.

3.1.2.1.7 Loss of Material in Nickel Alloy SG Secondary Side Handhold Cover RTD Bosses

In LRA Table 3.1.2-4-IP3, the applicant includes its AMR Item on management of loss of material in the IP3 SG secondary handhold cover RTD bosses, which are made from nickel alloy. The applicant aligned this AMR item to LRA AMR 3.1.1- 74 and to AMR Item IV.D1-15 in GALL Report, Volume 2 (GALL AMR Item IV.D1-15). For this AMR the applicant credited only the Water Chemistry Control Program – Primary and Secondary Program to manage loss of material in the component surfaces that are exposed to the secondary-side treated water environment (i.e., to FW).

GALL AMR IV.D1-15 pertains to the management of loss of material due to crevice corrosion or fretting in carbon steel SG antivibration bars in PWRs with recirculating SGs. In this AMR, the staff recommends that programs corresponding to GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M19, "Steam Generator Tube Integrity," be credited for aging management of loss of material due to crevice corrosion or fretting in chrome plate steel, stainless steel, or nickel alloy component surfaces that are exposed to secondary treated water or steam environments (i.e., to FW or steam).

The staff noted, that for other IP3 AMRs that the applicant had aligned to GALL AMR Item IV.D1-15 (e.g., those on loss of material of the IP3 SG antivibration bars and peripheral aligning rings SG FW nozzle thermal sleeves), the applicant credited both its Water Chemistry Control Program – Primary and Secondary Program and its Steam Generator Integrity Program

for aging management of loss of material in the component surfaces that are exposed to either a treated water or steam environment, which is consistent with the recommendations in GALL AMR IV.D1-15. The staff noted, however for the AMR on loss of material in the IP3 SG secondary handhold cover RTD bosses, the applicant only credited its Water Chemistry Control Program – Primary and Secondary Program to manage loss of material in the component surfaces that are exposed to the secondary-side treated water environment (i.e., FW). The staff noted that this was not consistent with the applicant's aging management basis for the SG antivibration bars and peripheral aligning rings or the SG FW nozzle thermal sleeves because the applicant did not credit its Steam Generator Integrity Program as an additional AMP for managing this aging effect. In Audit Item 209, the staff asked the applicant to provide its basis why the Steam Generator Integrity Program had not been credited for the SG secondary handhold cover RTD bosses.

By letter dated December 18, 2007, the applicant amended its LRA to add the Steam Generator Integrity Program as an additional program (i.e., in addition to the Water Chemistry Control Program – Primary and Secondary Program) to manage loss of material in both the IP3 SG secondary handhold cover RTD bosses and IP3 SG secondary handhold cover RTD well. The staff finds that the applicant's amended AMR for managing loss of material in both the IP3 SG secondary handhold cover RTD bosses and IP3 SG secondary handhold cover RTD well is acceptable because it is consistent with the staff recommendations in GALL AMR IV.D1-15 in that the applicant is crediting both its Water Chemistry Control Program – Primary and Secondary Program and its Steam Generator Integrity Program to manage loss of material in component surfaces that are exposed to the treated water environment.

The staff finds that the applicant's amended AMR for managing loss of material in both the IP3 SG secondary handhold cover RTD bosses and IP3 SG secondary handhold cover RTD well is acceptable because it is consistent with the staff's recommendations in GALL AMR IV.D1-15 that programs correspond to GALL AMP XI.M19, "Steam Generator Tubing Integrity" and GALL AMP XI.M2, "Water Chemistry," be credited to manage loss of material in chrome plated steel, stainless steel or nickel alloy SG component surfaces that are exposed to either a secondary treated water or steam environment. Audit Item 209 is resolved with respect to this AMR item.

3.1.2.1.8 Cracking in Stainless Steel SG Secondary Side Handhold RTD Wells

In LRA Table 3.1.2-4-IP3, the applicant includes its AMR item on management of cracking in the IP3 SG secondary side handhold RTD well, which is made from austenitic stainless steel. The applicant aligned this to LRA AMR 3.1.1-74 and to AMR Item IV.D1-14 in GALL Report, Volume 2 (GALL AMR Item IV.D1-14). In this AMR, the applicant credited only its Water Chemistry Control Program – Primary and Secondary Program to manage cracking in the stainless steel component surfaces that are exposed to secondary treated water.

GALL AMR IV.D1-14 pertains to the management of cracking in chrome plated steel, stainless steel, or nickel alloy SG antivibration bars in PWRs with recirculating SGs. In this AMR, the staff recommends that programs corresponding to GALL AMP XI.M2, "Water Chemistry," and GALL AMP XI.M19, "Steam Generator Tube Integrity," be credited for aging management of cracking due to SCC in chrome plated steel, stainless steel, or nickel alloy component surfaces that are exposed to secondary treated water or steam environments.

The staff noted, that for other IP3 AMRs that the applicant had aligned to GALL AMR Item IV.D1-14 (e.g., those on cracking of the IP3 SG flow restrictor and flow baffle distribution plate), the applicant credited both its Water Chemistry Control Program – Primary and Secondary Program and its Steam Generator Integrity Program for aging management of cracking in the component surfaces that are exposed to either treated water or steam, which is consistent with the recommendations in GALL AMR IV.D1-14. In contrast, the staff noted that for management of cracking in the IP3 SG secondary side handhold RTD well, the applicant credited only its Water Chemistry Control Program – Primary and Secondary Program to manage cracking in the stainless steel component surfaces that are exposed to treated water. In Audit Item 210, the staff asked the applicant why the Steam Generator Integrity Program had not been credited as an additional program to manage cracking in the IP3 SG secondary side handhold RTD well.

The applicant responded to Audit Item 209 in a letter dated December 18, 2007. In this letter the applicant amended its LRA to add the Steam Generator Integrity Program as an additional program (i.e., in addition to the Water Chemistry Control Program – Primary and Secondary Program) to manage cracking in the IP3 SG secondary handhold cover RTD well. The staff finds that the applicant's amended AMR for managing cracking in the IP3 SG secondary handhold cover RTD well is acceptable because it is consistent with the staff's recommendations in GALL AMR IV.D1-14 that programs correspond to GALL AMP XI.M19, "Steam Generator Tubing Integrity" and GALL AMP XI.M2, "Water Chemistry," be credited to manage cracking in chrome plated steel, stainless steel or nickel alloy SG component surfaces that are exposed to either a secondary treated water or steam environment. Audit Item 209 is resolved with respect to this AMR item.

3.1.2.1.9 Conclusion for AMRs Consistent with the GALL Report

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 aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are indeed consistent. Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their 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 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.1.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the reactor vessel, internals, and reactor coolant system components and provides 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 fracture toughness due to neutron irradiation embrittlement
- cracking due to SCC and IGSCC
- crack growth due to cyclic loading

- loss of fracture toughness due to neutron irradiation embrittlement and void swelling
- cracking due to SCC
- cracking due to cyclic loading
- loss of preload due to stress relaxation
- loss of material due to erosion
- cracking due to flow-induced vibration
- cracking due to SCC and irradiation-assisted SCC
- cracking due to PWSCC
- wall thinning due to flow-accelerated corrosion
- changes in dimensions due to void swelling
- cracking due to SCC and PWSCC
- cracking due to SCC, PWSCC, and irradiation-assisted SCC
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation. The staff determined whether the applicant adequately addressed the issues for which further evaluation is recommended. The staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.1.2.2. The staff's review of the applicant's further evaluation follows.

3.1.2.2.1 Cumulative Fatigue Damage

LRA Section 3.1.2.2.1 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. However, since many of the RCS components do not have fatigue usage factor calculations of their original design, Entergy will manage them using aging management programs in accordance with 10 CFR 54.21(c)(iii). Therefore, the staff assessments of these components are discussed below.

LRA Section 3.1.2.2.1 stated that, with the exception of the pressurizer support skirts, evaluation of the fatigue TLAA for the Class 1 portions of the reactor coolant pressure boundary piping and components, including those for interconnecting systems, is discussed in LRA Section 4.3.1. No fatigue analysis was required for the pressurizer support skirts. Cracking, including cracking due to fatigue, will be managed by the Inservice Inspection Program for the pressurizer support skirts.

SRP-LR Section 3.1.2.2.1 states that "[f]atigue is a time-limited aging analysis (TLAA) as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). This TLAA is addressed separately in Section 4.3, 'Metal Fatigue Analysis,' of this SRP-LR." For Westinghouse designed PWRs with recirculating SGs, SRP-LR Section 3.1.2.2.1 invokes the AMRs on "cumulative fatigue damage" in AMR Items 1, 5, 6, 7, 8, 9, and 10 of Table 1 to the GALL Report, Volume 1 and the plant-specific AMRs on "cumulative fatigue damage" for reactor vessel (RV) components, reactor vessel internal (RVI) components, RCS piping and pressurizer components, and SGs in Sections IV.A2, IV.B2, IVC2, and IV.D1 of the GALL Report Volume 1. In these AMRs, the GALL Report recommends that the PWR applicants credit their TLAAs on metal fatigue for management of "cumulative fatigue damage" in these components.

The staff noted that instead of referring to the aging effect term "cumulative fatigue damage," the applicant's applicable AMRs on metal fatigue refer to the aging effect as "cracking – fatigue." The staff finds the slight difference in terminology to be acceptable because the coalescence of any fatigue damage in the microstructure will manifest itself in the form of a fatigue crack. Based on this assessment, the staff verified that the applicant's AMRs on management "cracking –fatigue" in the LRA are those that correspond to the staff's AMRs in the GALL report which refer to management of "cumulative fatigue damage."

The staff verified that the applicant credits its TLAA on metal fatigue, as given in LRA Section 4.3 and its subsections, for management of "cumulative fatigue damage" in the IP ASME Code Class 1 RV components, RVI components, RCS piping, piping components, and piping elements, and pressurizer components, with the exception of metal fatigue analyses for the pressurizer support skirts.

SRP-LR Table 3.1.1, Item 7 addresses the TLAA for cumulative fatigue damage in steel and stainless steel RV support skirts and attachment welds in the RCS. The staff noted from LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 line items that the reactor vessels are not supported by RV support skirts, but instead use support pads that are welded to the underside of the primary inlet and outlet nozzles as the means of RV support. By letter dated December 18, 2007, the applicant responded to Audit Item 191A, and clarified that the support pads for the reactor vessel are part of the inlet and outlet nozzle forgings and are evaluated as part of those nozzles. The staff verified that that the metal fatigue analyses of the RV components, as discussed in LRA Section 4.3.1.1, include cumulative usage factor inputs for the RV inlet and outlet nozzles. Therefore, the staff finds that the management of the RV support pads is consistent with the guidance in SRP-LR Section 3.1.2.2.1. The staff also finds that the LRA does not need to include any AMR item on management of cumulative fatigue damage in RV support skirts because the IP designs do not use this type of component for RV support.

The staff noted that in the response to Audit Item 191A, Entergy confirmed that the CLB does not include any fatigue analysis for the pressurizer support skirts. Based on this review, the staff finds that the LRA does not need to include any AMR corresponding to GALL AMR IV.C2-10 on "cumulative fatigue damage" of pressurizer integral supports but the CLB does not include any fatigue analyses for these components at IP. Instead, the staff noted that the applicant is crediting its Inservice Inspection Program to manage cracking of these components, including the applicant's aging effect of "cracking – fatigue." The staff finds this to be an acceptable alternative because it is in conformance with the staff's AMR on cracking of pressurizer integral supports, as given in GALL AMR IV.C2-16.

LRA Tables 3.1.2-1-IP2, 3.1.2-1-IP3, 3.1.2-3-IP2, 3.1.2-3-IP3, 3.1.2-4-IP2, and 3.1.2-4-IP3 all indicate a TLAA line item referring to Table 3.1.1-7 for the RCS components. The LRA Table 2 line items associated with this TLAA do not include the support skirts and/or attachment welds for SGs and reactor coolant pumps (RCP). In Audit Item 191c, the staff requested IPNG to clarify how "cracking - fatigue" of the RCP and SG supports is managed. In its response, dated December 18, 2007, Entergy stated that the SGs are supported by pads attached to the primary channel heads and that the AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 for the primary channel heads (which include the integral pads) do not include any AMRs on "cracking –fatigue" because the CLB does not include any fatigue analyses for these components. The staff verified that the CLB does not include any fatigue analyses for the SG primary channel head support pads. Based on this determination, the staff finds that the TLAA on metal fatigue

of the Class 1 RCS piping components does not need to include any metal fatigue analysis for the SG primary channel head support pads because the CLB does not include any metal fatigue analysis for these components, and thus, the components are not subject to a metal fatigue TLAA under the TLAA definition criteria that are provided in 10 CFR 54.3.

The staff also noted that in the IP design, the RCPs are supported by feet that are directly attached to the pump casings and that these components are within the scope of the AMRs in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3. The staff verified that the CLB for IP does not include any metal fatigue analyses for these RCP supports. Based on this determination, the staff finds that the TLAA on metal fatigue of the Class 1 RCS piping components does not need to include any metal fatigue analysis for the RCP supports (i.e., feet) because the IP CLB does not include any metal fatigue analysis for these components and thus, the components are not subject to a metal fatigue TLAA under the TLAA definition criteria of 10 CFR 54.3.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.1 criteria. For those line items that apply to LRA Section 3.1.2.2.1, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.2 Loss of Material Due to General, 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.

(1) LRA Section 3.1.2.2.2 addresses loss of material due to general, pitting, and crevice corrosion in steam generator steel components exposed to secondary feedwater and steam, stating that the Water Chemistry Control - Primary and Secondary Program manages this aging effect. The One-Time Inspection Program will confirm the effectiveness of the Water Chemistry Control - Primary and Secondary Program by inspection of a representative sample of components crediting this program, including those in areas of stagnant flow.

    SRP-LR Section 3.1.2.2.2 states that loss of material due to general, pitting, and crevice corrosion may occur in the steel PWR SG shell assembly exposed to secondary feedwater and steam. Loss of material due to general, pitting, and crevice corrosion also may occur in the steel top head enclosure (without cladding) top head nozzles (vent, top head spray or reactor core isolation cooling, and spare) exposed to reactor coolant. The existing program controls reactor water chemistry to mitigate corrosion. However, control of water chemistry does not preclude loss of material due to pitting and crevice corrosion at locations with stagnant flow conditions. Therefore, the effectiveness of water chemistry control programs should be verified to ensure that corrosion does not occur. The GALL Report recommends further evaluation of programs to verify the effectiveness of water chemistry control programs. A one-time inspection of selected components at susceptible locations is an acceptable method to determine whether an aging effect is occurring or is slowly progressing such that the component's intended functions will be maintained during the period of extended operation.

LRA Table 3.1-1, Item 11, which addresses loss of material due to general, pitting, and crevice corrosion in the steel top head enclosure (without cladding) top head nozzles (vent, top head spray or reactor core isolation cooling, and spare) exposed to reactor coolant, is identified as not applicable because it applies to boiling water reactors (BWRs) only. Because IP2 and IP3 are PWRs, the staff finds that this component/aging effect combination does not apply to IP.

The staff noted that the SGs at IP2 and IP3 are Westinghouse Model 44F replacement SGs. The staff also noted that in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, the applicant aligned the following AMR line items for its SG components to LRA Table 1 AMR Item 3.1.1-12 and to GALL AMR IV.D2-8 (R-224) for once-through SG secondary side components: secondary side of the tubesheets, feedwater nozzles, secondary manways and manway covers, secondary handholds and handhold covers, secondary SG shell drain connection, secondary side instrument connections and SG blowdown piping, The staff noted that in the applicant AMRs for these components, the applicant credited its Water Chemistry Control Program – Primary and Secondary to manage loss of material in the component surfaces that are exposed secondary treated water or steam. The staff also noted that the applicant did not credit its One-Time Inspection Program or apply LRA AMR plant-specific Note 104, which states that the One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing loss of material in these components. In Audit Item 192, the staff asked the applicant to justify why the AMRs on loss of material in the secondary side of these carbon steel SG components did not credit LRA AMP B.1.27, One-Time Inspection Program, to verify the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing loss of material in the secondary side surfaces of these carbon steel SG components.

By letter dated December 18, 2007, the applicant clarified that the One-Time Inspection Program is credited with verifying the effectiveness of Water Chemistry Control Program – Primary and Secondary in managing loss of material in these secondary side SG components. The applicant stated that it would amend the AMR items in LRA Table 3.1.2-4-IP2 and 3.1.2-4-IP3 on loss of material in secondary side SG components referencing LRA Table 1 Item 3.1.1-12 and GALL AMR Item IV.D2-8 (R-224) to add plant-specific AMR Note 104, which credits a one-time inspection for verification of the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing this aging effect.

The staff verified that, in its letter of December 18, 2007, the applicant amended the applicable AMRs for the secondary side SG tubesheets, feedwater nozzles, manways and manway covers, handholds and handhold covers, shell drain connections, instrument connections, and blowdown piping to add LRA AMR Note 104 and to credit in One-Time Inspection Program for verification of the effectiveness of the Water Chemistry Control Program – Primary and Secondary in managing loss of material due to pitting and crevice corrosion in the secondary side component surfaces that are exposed to treated water. The staff finds that the amended AMRs are acceptable because the AMPs credited for aging management are consistent with the staff's aging management position that is recommended in SRP-LR Section 3.1.2.2.2, Item (1) and in the GALL AMRs that are based on this SRP-LR Section.

(2) LRA Section 3.1.2.2.2 addresses loss of material due to general, crevice, and pitting corrosion in BWR isolation condenser components exposed to reactor coolant, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.2 states that loss of material due to pitting and crevice corrosion may occur in stainless steel BWR isolation condenser components exposed to reactor coolant. Loss of material due to general, pitting, and crevice corrosion may occur in steel BWR isolation condenser components.

The staff finds that SRP-LR Section 3.1.2.2.2, Item (2) is not applicable to IP because IP2 and IP3 are PWRs, and the staff guidance in this SRP-LR section is only applicable to BWRs that are designed with isolation condensers.

(3) LRA Section 3.1.2.2.2 addresses loss of material due to general, crevice, and pitting corrosion in reactor vessel shells, heads, and welds; flanges; nozzles; penetrations; pressure housings; and safe ends, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.2 states that loss of material due to pitting and crevice corrosion may occur in stainless steel, nickel alloy, and steel with stainless steel or nickel alloy cladding flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shells, heads, and welds exposed to reactor coolant. This SRP-LR Section invokes AMR 14 in Table 1 of the GALL Report, Volume 1 and the associated AMRs in the GALL Report, Volume 2 which are applicable to stainless steel, nickel alloy, and steel with stainless steel or nickel alloy cladding flanges, nozzles, penetrations, pressure housings, safe ends, and vessel shells, heads, and welds in BWR-designed reactors.

The staff finds that SRP-LR Section 3.1.2.2.2, Item (3) is not applicable to IP because IP2 and IP3 are PWRs, and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors.

(4) LRA Section 3.1.2.2.2 addresses loss of material due to general, pitting, and crevice corrosion in the steel steam generator shell and transition cone exposed to secondary feedwater and steam, stating that the Inservice Inspection and Water Chemistry Control – Primary and Secondary Programs manage this aging effect. IP steam generators have been replaced. The replacement generators, Model 44Fs, have no high-stress region at the shell to transition cone weld as described in NRC Information Notice (IN) 90-04 and, as such, require no additional inspection procedures.

SRP-LR Section 3.1.2.2.2 states that loss of material due to general, pitting, and crevice corrosion may occur in the steel PWR steam generator upper and lower shell and transition cone exposed to secondary feedwater and steam. The existing program controls chemistry to mitigate corrosion and inservice inspection (ISI) to detect loss of material. The extent and schedule of the existing steam generator inspections are designed to ensure that flaws cannot attain a depth sufficient to threaten the integrity of the welds; however, according to IN 90-04, the program may not be sufficient to detect pitting and crevice corrosion, if general and pitting corrosion of the shell is known to occur. The GALL Report recommends augmented inspection to manage this aging effect. Furthermore, the GALL Report clarifies that this issue is limited to Westinghouse

Model 44 and 51 steam generators with a high-stress region at the shell to transition cone weld.

The staff noted that the staff's guidance in SRP-LR Section 3.1.2.2.2, Item (4) is applicable to only to Westinghouse SG Models 44 and 51 with high stress regions at the shell to transition cone weld. The IP SGs were replaced with Westinghouse Model 44F units which do not have this transition weld susceptible to pitting and crevice corrosion. Therefore, the staff determined that the IP SGs do not require any additional augmented inspections of the SG shell-to-transition cone regions as recommended in SRP-LR Section 3.1.2.2.2 or the GALL Report for Westinghouse Model 44 or 51 SG designs.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.2 criteria. For those line items that apply to LRA Section 3.1.2.2.2, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB 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.

(1) LRA Section 3.1.2.2.3 states that neutron irradiation embrittlement 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 4.2 documents the staff's review of the applicant's evaluation of this TLAA.

(2) LRA Section 3.1.2.2.3 addresses loss of fracture toughness due to neutron irradiation embrittlement, stating that the Reactor Vessel Surveillance Program manages reduction in fracture toughness due to neutron embrittlement of RV beltline materials to maintain the pressure boundary function of the reactor pressure vessel for the period of extended operation. The program evaluates radiation damage by pre- and post-irradiation testing of Charpy V-notch and tensile specimens from the most limiting plate in the reactor vessel core region with reports submitted as required by 10 CFR Part 50, Appendix H.

SRP-LR Section 3.1.2.2.3 states that loss of fracture toughness due to neutron irradiation embrittlement may occur in BWR and PWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. 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 Part 50, Appendix H, an applicant is required to submit its proposed withdrawal schedule for approval prior to implementation. Untested capsules placed in storage must be maintained for future insertion. Thus, further staff evaluation is required for license renewal. Specific recommendations for an acceptable AMP are provided in GALL Report Chapter XI, Section M31.

The staff reviewed the IP Reactor Vessel Surveillance Program that manages reduction in fracture toughness due to neutron embrittlement of the vessel beltline region material, excluding the vessel nozzles. During an onsite audit, the staff identified a statement in WCAP-16212, "Entergy Nuclear Operations, Incorporated, Indian Point Nuclear Generating Unit No. 3, Stretch Power Uprate, License Amendment Request Package," June 2004, that indicated that the typical fluence at the nozzle of an IP vintage vessel is about 0.6 percent of the peak vessel fluence. Based on this statement, the staff was concerned that the neutron fluence for the nozzle shell course could exceed $1x10^{17}$ n/cm^2. Therefore, via a telephone conference call, the staff requested that the applicant perform a neutron fluence evaluation for the components in the nozzle shell course. SER Section 4.2.2.2 documents the staff's evaluation of the applicant's analysis.

Based on the reviews discussed in the paragraphs above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.3 criteria. For those line items that apply to LRA Section 3.1.2.2.3, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.4 Cracking Due to Stress Corrosion Cracking and Intergranular 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.

(1) LRA Section 3.1.2.2.4 addresses cracking due to SCC and intergranular SCC (IGSCC) in BWR vessel leak detection lines, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.4 states that cracking due to SCC and IGSCC may occur in the stainless steel and nickel alloy BWR top head enclosure vessel flange leak detection lines.

The staff finds that SRP-LR Section 3.1.2.2.4, Item (1) is not applicable to IP2 and IP3 because IP2 and IP3 are PWRs, and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors.

(2) LRA Section 3.1.2.2.4 addresses cracking due to SCC and IGSCC in BWR isolation condenser components, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.4 states that cracking due to SCC and IGSCC may occur in stainless steel BWR isolation condenser components exposed to reactor coolant.

The staff finds that SRP-LR Section 3.1.2.2.4, Item (2) is not applicable to IP2 and IP3 because IP2 and IP3 are PWRs, and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors that are designed with isolation condensers.

Based on the above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.4, Items (1) and (2) do not apply to IP2 and IP3 because the guidance is applicable to BWR-designed reactors and because IP2 and IP3 are PWRs.

3.1.2.2.5 Crack Growth Due to Cyclic Loading

The staff reviewed LRA Section 3.1.2.2.5 against the criteria in SRP-LR Section 3.1.2.2.5.

LRA Section 3.1.2.2.5 states that growth of intergranular separations (underclad cracks) in the heat-affected zone under austenitic steel cladding is not an applicable aging effect because the IP vessel shells are not composed of SA 508-Cl 2 forgings with stainless steel cladding deposited with a high heat input welding process.

SRP-LR Section 3.1.2.2.5 states that crack growth due to cyclic loading could occur in reactor vessel shell forgings clad with stainless steel using a high-heat-input welding process. Growth of intergranular separations (underclad cracks) in the heat affected zone under austenitic stainless steel cladding is a TLAA to be evaluated for the period of extended operation for all SA 508-Cl 2 forgings where the cladding was deposited with a high heat input welding process. The methodology for evaluating the underclad flaw should be consistent with the current well-established flaw evaluation procedure and criterion in the ASME Section XI Code. See the SRP-LR, Section 4.7, "Other Plant-Specific Time-Limited Aging Analysis," for generic guidance for meeting the requirements of 10 CFR 54.21(c).

The staff confirmed that, in Table 5.1-2 of WCAP-16157-NP, Westinghouse Electric Company reports that the IP2 RV shells are fabricated from SA-533 alloy steel plate materials, and in WCAP-16251-NP, Revision 0, Westinghouse Electric Company reports that the IP3 RV shells are fabricated from SA-302 Grade B alloy steel plate materials. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the staff's guidance on RV underclad cracking, as given in SRP-LR Section 3.1.2.2.5, is not applicable to IP because the IP2 and IP3 RV shells are not fabricated from SA 508, Class 2 or Class 2 alloy steel forging materials.

3.1.2.2.6 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement and Void Swelling

The staff reviewed LRA Section 3.1.2.2.6 against the criteria in SRP-LR Section 3.1.2.2.6.

LRA Section 3.1.2.2.6 addresses loss of fracture toughness due to neutron irradiation embrittlement and change in dimensions (void swelling) that could occur in stainless steel and nickel alloy RVI components exposed to reactor coolant and neutron flux, stating that to manage loss of fracture toughness in such components, Entergy will (1) participate in industry programs for investigating and managing aging effects on reactor internals, (2) evaluate and implement the results of the industry programs pertinent to reactor internals, and (3) upon completion of these programs but not less than 24 months before the period of extended operation, submit an inspection plan for RVI to the staff for review and approval. This commitment is in the UFSAR Supplement, LRA Appendix A, Sections A.2.1.41 and A.3.1.41.

SRP-LR Section 3.1.2.2.6 states that "loss of fracture toughness due to neutron irradiation embrittlement and void swelling may occur in stainless steel and nickel alloy reactor vessel

internals components exposed to reactor coolant and neutron flux. The GALL Report recommends no further AMR if the applicant commits in the FSAR supplement (1) to participate in industry programs for investigating and managing aging effects on reactor internals, (2) to evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, to submit an inspection plan for reactor internals to the staff for review and approval."

For Westinghouse-designed reactor vessel internals, SRP-LR Section 3.1.2.2.6 refers to the staff's guidance in AMR 22 of Table 1 to the GALL Report, Volume 1, and in GALL AMRs IV.B2-3, IV.B2-6, IV.B2-9, IV.B2-17, IV.B2-18, and IV.B2-22. These AMRs are applicable to the management of loss of fracture toughness due to neutron irradiation embrittlement and/or void swelling in Westinghouse-designed RVI core baffle/former assembly plates; core baffle/former assembly bolts and screws; core barrel (CB), CB flange, CB outlet nozzles, and thermal shield; lower internals assembly fuel alignment pins, lower support plate column bolts, and clevis insert bolts; lower internals assembly core plate; and lower internals assembly – lower support forging or castings and lower support columns.

The commitment that is recommended by the staff includes a provision for PWR applicant's to submit an inspection plan for their RVI components that is based on the industry's augmented inspection program recommendations for PWR RVI components to the NRC for review and approval at least two years prior to entering the period of extended operation. The staff verified that LRA Tables 3.1.2-2-IP2 and 3.1.2-2-IP3 include all of the appropriate AMRs on loss of fracture toughness due neutron irradiation embrittlement and/or void swelling for the various IP2 and IP3 RVI components

The staff verified that Entergy has made the applicable commitment for IP2 and IP3 in Commitment 30, which was provided in Entergy letter dated March 24, 2008, and included in UFSAR Supplements A.2.1.41 and A.3.1.41 for the IP2 PWR Vessel Internals Program and the IP3 PWR Vessel Internals Program, respectively.

Thus, based on this review, the staff finds that the applicant has provided an acceptable basis for using Commitment 30 as its basis for aging management of loss of fracture toughness due to neutron irradiation embrittlement and/or void swelling in these IP2 and IP3 RVI components. The staff confirmed that Entergy has committed to participate in industry programs for investigating and managing aging effects on IP2 and IP3 RVI components in the UFSAR Supplement Sections A.2.1.41 and A.3.1.41, and therefore, the staff finds this acceptable.

Based on the applicant's commitment (Commitment 30),,the staff concludes that the applicant meets SRP-LR Section 3.1.2.2.6 criteria. For those line items that apply to LRA Section 3.1.2.2.6, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.7 Cracking Due to 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.

(1) LRA Section 3.1.2.2.7 addresses cracking due to SCC in the stainless steel bottom-mounted instrument (BMI) guide tube components exposed to reactor coolant, stating that the Inservice Inspection and Water Chemistry Control - Primary and Secondary Programs manages this aging effect by minimizing contaminants which promote SCC. The Inservice Inspection Program provides periodic pressure testing of these components.

SRP-LR Section 3.1.2.2.7, Item (1) states that cracking due to SCC may occur in the PWR stainless steel reactor vessel flange leak detection lines and BMI guide tubes exposed to reactor coolant. The GALL Report recommends that a plant-specific AMP be evaluated to ensure that this aging effect is adequately managed.

The staff verified that in LRA Table 3.1.2-1-IP2 and 3.1.2-1-IP3, the applicant credits its Water Chemistry Control – Primary and Secondary Program and Inservice Inspection Program to manage cracking in stainless steel BMI guide tube components, including the BMI guide tubes, BMI seal tables and BMI flux thimble tube bullet plugs, which are ASME Code Class 1 components. The staff also verified that the applicant's Inservice Inspection Program credits periodic ISI inspections and pressure testing ensures that the cracking of these components are not occurring and the water chemistry program manages the contaminants that are detrimental to SCC in stainless steel will be controlled by the applicant. The staff verified that, in GALL AMP XI.M1, "ASME Section XI Inservice Inspection, Subsection IWB, IWC, and IWD," the staff endorses inservice inspection programs as acceptable condition monitoring AMPs for managing the aging effects (including cracking) that are applicable ASME Code Class components. The staff verified that, in GALL AMP XI.M2 "Water Chemistry," the staff endorses water chemistry control programs as acceptable preventive/mitigative AMPs for controlling the water impurities that may induce aging effects (including cracking) in plant components (included ASME Code Class components) that are exposed to water-based coolants (i.e., treated water-type environments).

Based on this review, the staff finds that the applicant has provided an acceptable basis for crediting of the Inservice Inspection Program and the Water Chemistry Control Program – Primary and Secondary to manage cracking in these stainless steel BMI components because it conforms to the staff's recommendation that a plant-specific AMP or AMPs be evaluated and credited for aging management of cracking in the components, and because the crediting of these program is consistent with the bases in GALL AMP XI.M1 and XI.M2 for ASME Code Class components.

With regard to RV flange leak detection lines, the staff noted that the applicant identified that the RV flange leakage detection lines are composed of nickel alloy. As a result of this fabrication material, the AMR items in LRA Table 3.1.2-1-IP2 and 3.1.2-1-IP3 for the RV flange leakage detection lines are aligned to LRA Section 3.1.2.2.13, AMR Item 31 in LRA Table 3.1.1, and GALL IV.C2-13 for nickel alloy ASME Code Class 1 piping less than 4-inch NPS. The staff evaluates the applicant's AMRs on management of cracking in the nickel alloy RV flange leakage detection lines in SER Section 3.1.2.2.13.

(2) LRA Section 3.1.2.2.7 addresses cracking due to SCC in CASS reactor coolant system piping, piping components, and piping elements exposed to reactor coolant, stating that the Water Chemistry Control - Primary and Secondary and Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) programs manage this aging effect by (a) determining the susceptibility of CASS components to thermal aging embrittlement based on casting method, molybdenum content, and percent ferrite, and (b) accomplishing aging management for potentially susceptible components through either enhanced volumetric examination or plant- or component-specific flaw tolerance evaluation. The Inservice Inspection Program supplements these programs for some components.

SRP-LR Section 3.1.2.2.7, Item (2) states that cracking due to SCC may occur in Class 1 PWR CASS reactor coolant system piping, piping components, and piping elements exposed to reactor coolant. The existing program controls water chemistry to mitigate SCC. However SCC may occur in CASS components that do not meet the NUREG-0313 guidelines with regard to ferrite and carbon content. The GALL Report recommends further evaluation of a plant-specific program for these components to ensure this aging effect is adequately managed.

The staff noted that in LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3, the applicant included the following AMRs on cracking of CASS RCS piping, piping components, and piping elements that aligned to SRP-LR Section 3.1.2.2.7, Item (2) and the staff's guidance in GALL AMR IV.C2-3:

- Class 1 RCS piping elements made from CASS, including ASME Code Class 1 CASS elbows, flange components, scoops and tees
- The CASS pressurizer spray head, which in not categorized as an ASME Code Class component

For the ASME Code Class 1 CASS elbows, flange components, scoops and tees, the staff verified that the applicant identified the components as exceeding the NUREG-0313 acceptance criteria for cracking, and that the applicant's AMR credited a combination of the Water Chemistry Program – Primary and Secondary, the Inservice Inspection Program, and Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for management of cracking due to SCC in the component surfaces that are exposed to the reactor coolant. In contrast, for the CASS pressurizer spray head, the staff noted that the applicant only credited the Water Chemistry Program – Primary and Secondary and Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for management of this aging effect.

The staff verified that the applicant's Water Chemistry Program – Primary and Secondary is credited as an preventive and mitigative-based AMP for managing aging effects, including SCC, on metallic components from corrosion. The AMP is consistent with the staff's recommended program element criteria in GALL AMP XI.M2, "Water Chemistry." Based on this review, the staff finds that the applicant's crediting of the Water Chemistry Program – Primary and Secondary for the ASME Code Class 1 CASS elbows, flange components, scoops and tees, and for the non-ASME Code Class CASS

pressurizer spray head, is consistent with the staff recommended position in SRP-LR Section 3.1.2.2.7, Item 2 and in GALL AMR IV.C2-3, and is acceptable. The staff's evaluation of the Water Chemistry Program – Primary and Secondary is given in SER Section 3.0.3.2.17. The staff's evaluation of this program includes its basis for accepting that the Water Chemistry Program – Primary and Secondary, when enhanced, is an acceptable program for preventing or mitigating the aging effects that are applicable to metallic components as a result of corrosion. The staff's evaluation includes the basis for accepting this program for the management of cracking in these CASS components.

The staff noted that the applicant's Inservice Inspection Program (described in LRA Section B.1.18) is credited, in part, as an acceptable plant-specific condition monitoring program for the management of cracking in ASME Code Class 1 components, including ASME Code Class 1 CASS components. However, the staff noted that the inspections credited under this program might be either ultrasonic test (UT) examinations or enhanced VT-1 visual examinations. The staff sought additional clarification on how a UT method for CASS material would be capable of differentiating between a UT reflector that results from a actual flaw indication in the material as opposed to a UT reflector that results as a background noise signal from the complexity of the CASS microstructure or the complexity of the component geometry.

By letter dated December 30, 2008, the staff issued RAI 3.1.2.2.7.2-1, Part A, and asked the applicant to clarify how current state of the art UT methods, as implemented through the Inservice Inspection Program or other programs, would be adequate to detect cracks in CASS materials, or else to credit an alternative non-destructive inspection technique for the detection of cracking in the CASS components at IP if the current state-of-the-art UT techniques are incapable of detecting cracks in the CASS materials. This was identified as Open Item 3.1.2.2.7.2-1, Part A.

The applicant responded to RAI 3.1.2.2.7.2-1, Part A in a letter dated January 27, 2009. In this response, the applicant stated that current volumetric examination methods, (including UT) are not currently reliable for the detection of cracking in CASS materials and therefore are not credited for aging management of cracking in the CASS components, including the CASS pressurizer spray heads. Thus, the staff noted that the applicant is currently relying on enhanced VT-1 visual examination methods to manage cracking in the CASS pressurizer spray heads. The staff finds this to be acceptable because current UT technology methods are currently unable to differentiate between UT reflections that result from actual flaw indications in the CASS material and those UT reflections that result from a background noise signal due to the complexity of the CASS microstructure. In addition, ASME Code, Section XI lists VT-1 visual examination methods as acceptable examination techniques for the detection of cracking. RAI 3.1.2.2.7.2-1, Part A is resolved and Open Item 3.1.2.2.7.2-1, Part A is closed with respect to the inspection techniques that are credited to manage cracking in the CASS pressurizer spray heads.

The staff also noted that the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program (LRA Section B.1.37) was credited for: (1) evaluation of thermal aging embrittlement in both the Code Class 1 CASS elbows, flanges, tees, and scoops, and in the non-ASME Code Class CASS pressurizer spray head, and (2) detection of cracking in the non-ASME Code Class CASS pressurizer spray head.

The staff verified that the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is credited as an acceptable condition monitoring program for the management of reduction of fracture toughness as a result of thermal aging in CASS components. The staff also verified that this program has been identified as a new AMP that is consistent with the staff's recommended program element criteria in GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)."

The staff also noted that the applicant's program includes a flaw evaluation methodology for CASS components that are susceptible to thermal aging embrittlement. This AMP may propose UT or enhanced VT-1 visual examinations as an indirect basis for managing loss/reduction of fracture toughness as a result of thermal aging. However, the staff noted that the applicant's program is not specifically credited for the management of cracking in CASS components. Thus, while the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program could be used as an acceptable basis for meeting the staff's "flaw evaluation methodology for CASS components that are susceptible to thermal aging embrittlement" criterion in GALL AMR IV.C2-3, the staff noted that the program may not be valid to manage cracking in these components because the aging effect addressed by the corresponding program in GALL AMP XI.M12 is limited to management of loss/reduction of fracture toughness in CASS components.

By letter dated December 30, 2008, the staff issued RAI 3.1.2.2.7.2-1, Part B, and asked the applicant to justify its basis crediting AMP B.1.37, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, to manage and detect for cracking in the CASS pressurizer spray heads at IP2 and IP3; GALL AMP XI.M12 only credits this type of program for management of reduction or fracture toughness in components made from CASS and the program may not actually be performing inspections of this component (i.e., the program has the option only to do the flaw tolerance evaluation without implementation of either a UT or EVT-1 examination). This was identified as Open Item 3.1.2.2.7.2-1, Part B.

The applicant responded to RAI 3.1.2.2.7.2-1, Part B in a letter dated January 27, 2009. In this response, the applicant stated that the Water Chemistry Program is credited for the management of cracking in the CASS pressurizer spray heads and that the One-Time Inspection Program will be used to verify the effectiveness of the Water Chemistry Program in managing cracking of these components. The staff noted that the applicant's response to RAI 3.1.2.2.7.2-1 clarified that this one-time inspection will be done using enhanced VT-1 techniques (EVT-1). The staff finds this to be acceptable because it is in conformance with the recommend AMPs for managing cracking in CASS pressurizers in GALL AMR IV.C2-17, and with the recommended inspection methods in GALL AMP XI.M12 for detecting cracking in CASS materials. RAI 3.1.2.2.7.2-1, Part B is resolved and Open Item 3.1.2.2.7.2-1, Part B is closed.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.7 criteria. For those line items that apply to LRA Section 3.1.2.2.7, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended

functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.8 Cracking Due to Cyclic Loading

The staff reviewed LRA Section 3.1.2.2.8 against the criteria in SRP-LR Section 3.1.2.2.8.

(1) LRA Section 3.1.2.2.8 addresses cracking due to cyclic loading in BWR jet pump sensing lines, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.8 states that cracking due to cyclic loading may occur in the stainless steel BWR jet pump sensing lines.

The staff verified that SRP-LR Section 3.1.2.2.8, Item (1) is not applicable to IP2 and IP3 because IP2 and IP3 are PWRs and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors that are designed with stainless steel jet pump sensing lines.

(2) LRA Section 3.1.2.2.8 addresses cracking due to cyclic loading in BWR isolation condenser components, stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.8 states that cracking due to cyclic loading may occur in steel and stainless steel BWR isolation condenser components exposed to reactor coolant.

The staff verified that SRP-LR Section 3.1.2.2.8, Item (2) is not applicable to IP2 and IP3 because IP2 and IP3 are PWRs and the staff guidance in this SRP-LR section is only applicable to BWR-designed reactors that are designed with isolation condensers.

Based on the above, the staff concludes that SRP-LR Section 3.1.2.2.8 criteria do not apply to the IP2 and IP3 LRA.

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.

LRA Section 3.1.2.2.9 addresses loss of preload due to stress relaxation (creep), stating that this aging effect would be a concern only in very high temperature (more than 700 °F) applications as stated in ASME Code, Section II, Part D, Table 4. No IP internals components operate at more than 700 °F. Therefore, loss of preload due to stress relaxation (creep) is not an applicable aging effect for reactor vessel internals components. Nevertheless, loss of preload of stainless steel and nickel alloy reactor vessel internals components will be managed to the extent that industry-developed reactor vessel internals AMPs address the aging effect. The applicant's commitment to these programs is in the UFSAR Supplement, LRA Appendix A, Sections A.2.1.41 and A.3.1.41.

SRP-LR Section 3.1.2.2.9 states that loss of preload due to stress relaxation may occur in stainless steel and nickel alloy PWR RVI screws, bolts, tie rods, and hold-down springs exposed to reactor coolant. The GALL Report recommends no further AMR if the applicant

commits in the FSAR supplement (1) to participate in the industry programs for investigating and managing aging effects on reactor internals, (2) to evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, to submit an inspection plan for reactor internals to the staff for review and approval.

For Westinghouse-designed RVI, SRP-LR Section 3.1.2.2.9 refers to the staff's guidance in AMR 27 of Table 1 to the GALL Report, Volume 1, and in GALL AMRs IV.B2-5, IV.B2-14, IV.B2-25, IV.B2-33, and IV.B2-38, as applicable to the management of loss of preload due to stress relaxation in Westinghouse-designed RVI baffle/former bolts, clevis insert bolts, lower support plate column bolts, upper internals assembly hold-down springs, and upper support column bolts.

The staff verified that Entergy has made the applicable commitment for these IP2 and IP3 AMRs in Commitment 30, which was provided in a letter dated March 24, 2008, and included in UFSAR Supplements A.2.1.41 and A.3.1.41 for the IP2 and IP3 PWR Vessel Internals Programs, respectively.

Thus, based on this review, the staff finds that the applicant has provided an acceptable basis for using Commitment 30 as its basis for aging management of loss of preload due to stress relaxation in the RVI bolting, hold-down springs and fastener components at IP2 and IP3 because the AMRs for the components are in conformance with the staff's recommended aging management position in GALL AMRs IV.B2-5, IV.B2-14, IV.B2-25, IV.B2-33, and IV.B2-38.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.9 criteria. For those line items that apply to LRA Section 3.1.2.2.9, the staff determines that the LRA is consistent with the GALL Report, and that the applicant's Commitment 30 will adequately address management of loss of preload in the RVI bolting, hold-down springs, and fasteners 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 Material 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.

LRA Section 3.1.2.2.10 addresses loss of material due to erosion that could occur in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater, stating that this aging effect is not applicable because the IP SG design employs no feedwater impingement plate.

SRP-LR Section 3.1.2.2.10 states that loss of material due to erosion may occur in steel steam generator feedwater impingement plates and supports exposed to secondary feedwater.

The staff verified that the replacement steam generators (SGs) at IP are Westinghouse Model 44F SGs and that this SG design does not include steel SG impingement plates or supports. Thus, based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the staff's recommended guidance in SRP-LR Section 3.1.2.2.10 is not applicable to the IP SGs because the new SGs are not designed with feedwater impingement plates and supports that are exposed to secondary water.

Based on the above, the staff concludes that recommended guidance in SRP-LR Section 3.1.2.2.10 does not apply to IP.

3.1.2.2.11 Cracking Due to Flow-Induced Vibration

The staff reviewed LRA Section 3.1.2.2.11 against the criteria in SRP-LR Section 3.1.2.2.11.

LRA Section 3.1.2.2.11 addresses cracking due to flow-induced vibration of BWR steam dryers by stating that this aging effect is not applicable to IP, which are PWRs.

SRP-LR Section 3.1.2.2.11 states that cracking due to flow-induced vibration could occur for the BWR stainless steel steam dryers exposed to reactor coolant.

The staff finds that SRP-LR Section 3.1.2.2.11 is not applicable to IP because IP2 and IP3 are PWRs and the staff guidance in this SRP-LR section is only applicable to the design of steam dryers in BWR-designed reactors.

Based on the above, the staff concludes that the guidance in SRP-LR Section 3.1.2.2.11 does not apply to IP.

3.1.2.2.12 Cracking Due to Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.12 against the criteria in SRP-LR Section 3.1.2.2.12.

LRA Section 3.1.2.2.12 addresses cracking due to SCC and irradiation-assisted stress corrosion cracking (IASCC) in PWR stainless steel reactor vessel internal (RVI) components exposed to reactor coolant, stating that, to manage cracking such components, Entergy maintains the Water Chemistry Control - Primary and Secondary Program and will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the staff for review and approval. The applicant's commitment to these programs is in the UFSAR Supplement, LRA Appendix A, Sections A.2.1.41 and A.3.1.41.

SRP-LR Section 3.1.2.2.12 states that SCC and IASCC may occur in PWR stainless steel reactor internals exposed to reactor coolant. The existing program controls water chemistry to mitigate these aging effects. The GALL Report recommends no further AMR if the applicant commits in the FSAR supplement (1) to participate in the industry programs for investigating and managing aging effects on reactor internals, (2) to evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, to submit an inspection plan for reactor internals to the staff for review and approval.

The staff verified that Entergy has made the applicable commitment for these AMRs in Commitment 30, which was provided in a letter dated March 24, 2008, and included in UFSAR

Supplements A.2.1.41 and A.3.1.41 for the IP2 and IP3 PWR Vessel Internals Programs, respectively.

Thus, based on this review, the staff finds that the applicant has provided an acceptable basis for using Commitment 30 as its basis for aging management of cracking due to SCC or IASCC in these RVI components because the AMRs for the components are in conformance with the staff's recommended aging management position in SRP-LR Section 3.1.2.2.12 and the aforementioned AMRs in GALL AMRs IV.B2-2, IV.B2-8, IV.B2-10, IV.B2-12, IV.B2-24, IV.B2-30, IV.B2-36, and IV.B2-42.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.12 criteria. For those line items that apply to LRA Section 3.1.2.2.12, the staff determines that the LRA is consistent with the GALL Report and that the applicant's Commitment 30 will adequately address management cracking of the RVI components 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 Cracking Due to Primary Water Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.13 against the criteria in SRP-LR Section 3.1.2.2.13.

LRA Section 3.1.2.2.13 addresses cracking due to PWSCC, stating that the Water Chemistry Control - Primary and Secondary, Inservice Inspection, and Nickel Alloy Inspection programs manage this aging effect for most nickel alloy components. The Nickel Alloy Inspection Program implements applicable NRC orders and will implement applicable (1) bulletins and generic letters and (2) staff-accepted industry guidelines. UFSAR Supplement Sections A.2.1.20 and A.3.1.20 include this commitment.

SRP-LR Section 3.1.2.2.13 states that cracking due to PWSCC may occur in PWR components made of nickel alloy and steel with nickel alloy cladding, including reactor coolant pressure boundary components and penetrations inside the reactor coolant system such as pressurizer heater sheathes and sleeves, nozzles, and other internal components. Except for reactor vessel upper head nozzles and penetrations, the GALL Report recommends ASME Code, Section XI ISI (for Class 1 components) and control of water chemistry. For nickel alloy components, no further AMR is necessary if the applicant complies with applicable NRC orders and commits in the FSAR supplement to implement applicable (1) bulletins and generic letters, and (2) staff-accepted industry guidelines.

For Westinghouse-designed PWRs with recirculating SGs, SRP-LR Section 3.1.2.2.13 invokes AMR Item 31 in Table 1 of the GALL Report, Volume 1 and AMR Items IV.A2-12, IV.A2-19, IV.C2-13, IV.C2-21, IV.C2-24, and IV.D1-4, as applicable to the management of cracking due to PWSCC in nickel alloy RV core support pads/lugs; RV bottom mounted instrumentation (BMI) tubes; RCS piping, piping components and piping elements; pressurizer instrumentation nozzles, heater sheaths and sleeves, heater bundle diaphragm plates, manways and flanges; pressurizer surge and steam space nozzles and welds; and SG instrument penetrations and primary side nozzles, safe ends, and welds.

The staff noted that of the possible nickel alloy components listed in the GALL AMRs that are invoked by this SRP-LR item, the Table 2 LRA Tables for the IP2 and IP3 RCS designs only include the following nickel alloy components:

- RV core support pads/lugs (Refer to LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3)
- RV BMI tubes (Refer to LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3)
- ASME Code Class 1 piping, piping components, and piping elements (Refer to LRA Tables 3.1.2-3-IP2 and 3.1.2-3-IP3)

The staff verified that the applicant appropriately aligned its AMRs for these nickel alloy components to LRA AMR 3.1.1-31, which credits the Water Chemistry Control Program – Primary and Secondary, the Inservice Inspection Program, and the Nickel Alloy Inspection Program to manage PWSCC-induced cracking in the nickel alloy component surfaces that are exposed to the borated treated water environment of the reactor coolant. The staff finds this to be acceptable because it is in conformance with recommendations for aging management in AMR Item 31 in Table 1 of the GALL Report, Volume 1. The staff also verified that for the AMRs on cracking of the nickel alloy RV BMI tubes and nickel alloy ASME Code Class 1 piping, piping components, and piping elements, the applicant credited its Water Chemistry Control Program – Primary and Secondary, Inservice Inspection Program, and Nickel Alloy Inspection Program to manage PWSCC-induced cracking in the nickel alloy component surfaces that are exposed to the treated water environment of the reactor coolant. The staff noted that the AMPs credited for aging management of cracking due to PWSCC is in conformance with the staff's recommended aging management position and the AMPs that are recommended for aging management in SRP-LR Section 3.1.2.2.13 and GALL AMRs IV.A2-19, and IV.C2-13. Based on this review, the staff finds that the crediting of these AMPs for management of cracking in the nickel alloy RV BMI tubes and nickel alloy ASME Code Class 1 piping, piping components, and piping elements is acceptable because it is in conformance with the AMPs that are recommended for aging management in SRP-LR Section 3.1.2.2.13 and in GALL AMRs IV.A2-19 and IV.C2-13.

The staff noted that in the applicant's letter of December 18, 2007, the applicant amended its aging management basis in LRA AMR 3.1.1-31 and in the AMRs in LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3 to credit its Water Chemistry Control Program – Primary and Secondary, its Inservice Inspection Program, and its Nickel Alloy Inspection Program to manage cracking of its RV internals core support lugs (pads). GALL AMR IV.A2-12 recommends that AMPs corresponding to GALL AMP XI.M2, "Water Chemistry," and XI.M1, "ASME Section XI Inservice Inspection, Subsections, IWB, IWC, and IWD," be credited to manage cracking in RV core support pads or lugs. In addition, for RV core support pads or lugs that are made of nickel-alloy materials, GALL AMR IV.A2-12 recommends that PWR applicant provide a commitment on the FSAR supplement to submit a plant-specific AMP to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines. . The staff verified that the applicant placed this commitment for the nickel-alloy components as part of the applicant's UFSAR Supplements A.2.1.30 and A.3.1.30 for the Nickel Alloy Inspection Program, which were amended in the applicant's letter of December 18, 2007 to include this commitment. The staff finds that the applicant's amended AMR basis for managing cracking of the RV internal core support lugs is acceptable because it is in conformance with the staff's aging management recommendations for these components in GALL AMR IV.A2-12.

The staff also noted that in SRP-LR Section 3.1.2.2.13, the staff states that no further evaluation of cracking due to PWSCC is necessary for ASME Code Class 1 nickel alloy components if PWR applicants for license renewal state in the LRA UFSAR Supplements that they will comply with applicable NRC Orders on nickel alloy cracking and if they place a commitment in their LRA UFSAR supplement to "implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines." The staff reviewed LRA Section A.2.1.20, "Nickel Alloy Inspection Program," and noted that in the applicant's LRA letter of March 12, 2008, the applicant responded to RAI 3.0.3.3.5-2 and committed to: (1) comply with applicable NRC Orders on nickel alloy components and (2) conform to applicable NRC Bulletins, Generic Letters and NRC-staff accepted industry guidelines associated with nickel alloy components. The staff also verified that in the applicant's letter of June 11, 2008, the applicant amended UFSAR Supplement Sections A.2.1.20 for the IP2 Nickel Alloy Inspection Program and UFSAR Supplement Section A.3.1.20 for the IP3 Nickel Alloy Inspection Program and placed the nickel alloy commitment referred to in the applicant's letter of June 11, 2008, in the appropriate UFSAR Supplement Sections for the applicant's Nickel Alloy Inspection Program. The staff noted that this is consistent with the staff's recommended further evaluation guidance and nickel alloy commitment basis that is provided in SRP-LR Section 3.1.2.2.13 and in GALL AMRs IV.A2-12, IV.A2-19, and IV.C2-13

The staff verified that, consistent with the documentation in WCAP-14574-A, which was approved by the staff in a safety evaluation dated October 26, 2000 (ADAMS Accession number ML003763768), the applicant's AMRs in the LRA indicated that the IP2 and IP3 pressurizer designs do not include nickel alloy pressurizer components. The staff noted this was consistent with the design basis information for the IP2 and IP3 pressurizer designs that was provided in WCAP-14574-NP-A. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that recommendations in GALL AMRs IV.C2-21 and IV.C2-24 are not applicable to the IP2 and IP3 LRA because the staff has verified, based on a review of WCAP-14574-NP-A, that the IP2 and IP3 pressurizer designs do not include any nickel alloy pressurizer instrumentation nozzles, heater sheaths and sleeves, heater bundle diaphragm plates, manways and flanges; pressurizer surge and steam space nozzles and welds.

The staff also noted that, in LRA Table 3.1.2-4-IP2 and 3.1.2-4-IP3, the applicant did include AMRs for cracking of the nickel alloy SG primary nozzle closure rings, and that in these AMRs, the applicant credited only its Water Chemistry Control Program – Primary and Secondary to manage cracking in the component surfaces that are exposed to borated treated water. By letter dated December 30, 2008, the staff issued RAI 3.1.2-1, Part C, and asked the applicant to justify why the applicant has aligned its AMRs for the SG primary nozzle closure rings to GALL AMR IV.D1-6 which is for SG divider plates, and why the Inservice Inspection Program was not credited in addition to the Water Chemistry Control Program – Primary and Secondary to manage cracking due to SCC or PWSCC in the SG primary nozzle closure rings. This is part of Open Item 3.1.2-1. The issue on whether the AMRs in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3 on cracking of nickel alloy SG primary nozzle closure rings need to credit the Inservice Inspection Program as an additional AMP for managing cracking in the SG primary nozzle closure rings is pending acceptable resolution of RAI 3.1.2-1, Part C (Open Item 3.1.2-1).

The applicant responded to RAI 3.1.2-1, Part C in a letter dated January 27, 2009. In this response the applicant explained that GALL AMR IV.D1-6 is only applicable to SG divider plates

which are not part of the primary pressure boundary. The applicant also explained that the SG primary closure nozzle closure rings are fabricated from nickel alloy materials, they are not reactor coolant pressure boundary components, and are therefore not subject to ASME Code, Section XI inservice inspection requirements. The staff finds the applicant's response to RAI 3.1.2-1, Part C provides an acceptable basis for not crediting the ISI program for the SG feedwater nozzle closure rings because the rings are not categorized as ASME Code Class 1 reactor coolant pressure boundary components, and because the applicant would only be required to apply the ISI requirements of the applicant's Inservice Inspection Program to the rings if they were ASME Code Class 1 reactor coolant pressure components. The staff also finds that the applicant has provided an acceptable basis for using GALL AMR Item IV.D1-6 for the SG primary nozzle closure rings because GALL AMP IV.-D1-6 is applicable to SG divider plates made from nickel alloy materials. RAI 3.1.2-1, Part C is resolved and Open Item 3.1.2-1 is closed with respect to the AMPs that need to be credited for aging management of cracking due to PWSCC of the SG feedwater nozzle closure rings.

Based on the programs identified above, and resolution of Open Item 3.1.2-1, Part C, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.13 criteria. For those line items that apply to LRA Section 3.1.2.2.13, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.14 Wall Thinning Due to Flow-Accelerated Corrosion

The staff reviewed LRA Section 3.1.2.2.14 against the criteria in SRP-LR Section 3.1.2.2.14.

LRA Section 3.1.2.2.14 addresses wall thinning due to flow-accelerated corrosion, stating that it could occur in steel feedwater inlet rings and supports. The Steam Generator Integrity Program manages loss of material due to flow-accelerated corrosion in the feedwater inlet ring using periodic visual inspections.

SRP-LR Section 3.1.2.2.14 states that wall thinning due to flow accelerated corrosion may occur in steel feedwater inlet rings and supports. The GALL Report references IN 91-19, "Steam Generator Feedwater Distribution Piping Damage," for evidence of flow-accelerated corrosion in steam generators and recommends that a plant-specific AMP be evaluated because existing programs may not be capable of mitigating or detecting wall thinning due to flow accelerated corrosion.

For Westinghouse-design PWRs with recirculation SGs, SRP-LR Section 3.1.2.2.14 invokes AMR Item 32 in the GALL Report, Volume 1 and AMR Item IV.D1-26, as applicable to loss of material (wall thinning) due to flow accelerated corrosion in SG FW inlet rings and supports.

The staff verified that in LRA Tables 3.1.2-4-IP2 and 3.1.2-4-IP3, the applicant includes AMRs on management of loss of material (wall thinning) in the SG feedwater rings and fittings that are made from carbon steel and that are exposed internally to treated water. The staff also verified that in these AMRs, the applicant credits a combination of its Water Chemistry Control Program – Primary and Secondary and its Steam Generator Integrity Program to manage loss of material in the internal SG FW ring surfaces.

The staff noted that in GALL AMR IV.D1-26, the staff recommends that a plant-specific program be evaluated and credited to address operating experience discussed in IN 91-19. The staff requested the applicant to discuss the type of visual inspections that could detect the wall thinning of carbon steel FW rings and supports, as noted in IN 91-19 (Audit Item 199). Although the description of the SG integrity AMP includes other mechanically induced phenomena, such as denting, wear, impingement damage, and fatigue, no details are found in the LRA about how the inspection methods and their evaluation are performed with regard to loss of material in carbon steel FW inlet ring and supports in the IP SGs. In response, dated December 18, 2007, the applicant stated that the SG integrity program includes processes for monitoring and maintaining secondary side components. Visual inspections are performed by qualified vendors.

The staff notes that SGs were replaced at IP2 in 2001 and at IP3 in 1989. Therefore, the FW ring inspections have not been performed in the IP2 SGs, but are scheduled in two of its SGs in 2010. However, the FW ring inspections were performed in IP3 SGs in: 1992 (all four), 1997 (34SG), 1999 (33SG), 2001 (32SG), and 2007 (31SG and 32SG). The inspections included visual examinations of the outer diameter (OD) of the ring and a fiberscope inspection of the inner diameter (ID) of 5 selected J-nozzles of 36 total and the FW ring tee. The inspection also included various support structures including the feedring hangers. No anomalies were noted other than minor washed out areas of the feedring beneath the outlet of the J-nozzles. The next inspection is scheduled in two SGs in 2013. Therefore, the staff concluded that wall thinning due to flow-accelerated corrosion is properly managed by the SG integrity program and hence, finds it acceptable.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.14 criteria. For those line items that apply to LRA Section 3.1.2.2.14, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.15 Changes in Dimensions Due to Void Swelling

The staff reviewed LRA Section 3.1.2.2.15 against the criteria in SRP-LR Section 3.1.2.2.15.

LRA Section 3.1.2.2.15 addresses changes in dimensions due to void swelling, stating that it could occur in stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant. To manage changes in dimensions of such components, Entergy will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the staff for review and approval. This commitment is in the UFSAR Supplement, LRA Appendix A, Sections A.2.1.41 and A.3.1.41.

SRP-LR Section 3.1.2.2.15 states that changes in dimensions due to void swelling may occur in stainless steel and nickel alloy PWR internal components exposed to reactor coolant. The GALL Report recommends no further AMR if the applicant commits in the FSAR supplement (1) to participate in the industry programs for investigating and managing aging effects on

reactor internals, (2) to evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, to submit an inspection plan for reactor internals to the staff for review and approval.

For Westinghouse-designed reactor vessel internals, SRP-LR Section 3.1.2.2.15 refers to the staff's guidance in AMR 33 of Table 1 to the GALL Report, Volume 1, and in GALL AMRs IV.B2-1, IV.B2-4, IV.B2-7, IV.B2-11, IV.B2-15, IV.B2-19, IV.B2-23, IV.B2-27, IV.B2-29, IV.B2-35, IV.B2-39, and IV.B2-41, as applicable to the management of changes in dimensions due to void swelling in Westinghouse-designed RVI baffle/former plates; baffle/former bolts; core barrel (CB), CB flange, CB outlet nozzles and thermal shield; flux thimble guide tubes; flux thimble guide tubes; lower internal assembly – fuel alignment pins, lower support plate column bolts, and clevis insert bolts; lower internals assembly – lower core plate radial keys and clevis inserts; lower internals assembly – lower support casting or forging and lower support columns; RCCA guide tube assemblies – RCCA guide tube bolts and RCCA guide tube support pins; RCCA guide tube assemblies – RCCA guide tubes; upper internals assembly – upper support columns; upper internals assembly – upper support column bolts, upper core plates, and fuel alignment pins; and upper internals assembly – upper support plates, upper core plates, and hold-down springs.

The staff verified that Entergy has made the applicable commitment for these AMRs in Commitment 30, which was provided in Entergy letter dated March 24, 2008, and included in UFSAR Supplements A.2.1.41 and A.3.1.41 for the IP2 and IP3 PWR Vessel Internals Programs, respectively.

Thus, based on this review, the staff finds that the applicant has provided an acceptable basis for using Commitment 30 as its basis for aging management of changes in dimension due to void swelling in these RVI components because the AMRs for the components are in conformance with the staff's recommended aging management position in SRP-LR Section 3.1.2.2.12 and GALL AMRs IV.B2-1, IV.B2-4, IV.B2-7, IV.B2-11, IV.B2-15, IV.B2-19, IV.B2-23, IV.B2-27, IV.B2-29, IV.B2-35, IV.B2-39, and IV.B2-41.

Based on the programs identified above, the staff concludes that the applicant's programs meet SRP-LR Section 3.1.2.2.15 criteria. For those line items that apply to LRA Section 3.1.2.2.15, the staff determines that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2.16 Cracking Due to Stress Corrosion Cracking and Primary Water Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.16 against the criteria in SRP-LR Section 3.1.2.2.16.

(1) LRA Section 3.1.2.2.16 addresses cracking due to SCC in stainless steel control rod drive head penetration components and on the primary coolant side of steel steam generator heads clad with stainless steel, stating that the Water Chemistry Control - Primary and Secondary and Inservice Inspection programs manage this aging effect. The Water Chemistry Control - Primary and Secondary, Inservice Inspection, and

Reactor Vessel Head Penetration Inspection programs manage cracking of nickel alloy control rod drive head penetration components due to PWSCC. The Reactor Vessel Head Penetration Inspection Program implements applicable NRC orders and will implement applicable (1) bulletins and generic letters and (2) staff-accepted industry guidelines. The UFSAR Supplement, LRA Appendix A, Sections A.2.1.30 and A.3.1.30, state this commitment. The Water Chemistry Control - Primary and Secondary and Steam Generator Integrity programs manage cracking for the steam generator tubesheets.

SRP-LR Section 3.1.2.2.16, Item (1) states that cracking due to SCC may occur on the primary coolant side of PWR steel steam generator upper and lower heads, tubesheets, and tube-to-tube sheet welds made or clad with stainless steel. Cracking due to PWSCC may occur on the primary coolant side of PWR steel steam generator upper and lower heads, tubesheets, and tube-to-tube sheet welds made or clad with nickel alloy. The GALL Report recommends ASME Code, Section XI ISI and control of water chemistry to manage this aging effect and recommends no further AMR for PWSCC of nickel alloy if the applicant complies with applicable NRC orders and commits in the FSAR supplement to implement applicable (1) bulletins and generic letters, and (2) staff-accepted industry guidelines.

The staff noted that, in LRA Tables 3.1.2-1-IP2 and 3.1.2-1-IP3, consistent with GALL Report, the applicant credited its Water Chemistry Control Program – Primary and Secondary and Inservice Inspection Program to manage cracking of the stainless steel CRD pressure housings. The staff noted that this is appropriate for the stainless steel base metals used to fabricate the CRD pressure housings. However, the staff noted that the welds used to join the stainless steel CRD pressure housings to the nickel alloy upper RVCH penetration nozzles (e.g., CRD mechanism penetration nozzles) would normally be fabricated from bimetallic (nickel alloy) weld materials. Thus, the staff noted that for the CRD housing bimetallic weld materials, the applicant did not include the appropriate commitment in UFSAR Supplements A.2.1.20 and A.3.1.20. By letter dated December 30, 2008, the staff issued RAI 3.1.2-1, and asked whether the weld used to secure the CRD housings to the nickel alloy upper RVCH penetration nozzles were made of nickel alloy filler weld materials. If so, the staff requested that the applicant amend the LRA to provide AMRs on the IP2 and IP3 SG CRD pressure housing-to-CRD penetration nozzle welds that credit the Water Chemistry Control Program – Primary and Secondary, the Inservice Inspection Program, and the Nickel Alloy Inspection Program, as bases for managing cracking of these bimetallic (nickel alloy) weld materials along with the appropriate commitment that was made for Nickel alloy components in the applicant's letter dated March 12, 2008, as amended by letter dated June 11, 2008. This was identified as Open Item 3.1.2-1, Part A.

In its response dated January 27, 2009, the applicant clarified that the CETNA nozzles used in the upper RV head designs are fabricated from stainless steel and do not include any nickel alloy base metal or weld materials. Instead, the applicant clarified that the CETNA assemblies are fabricated as follows:

A CET head port adapter is connected to the penetration housing adapter flange, and then connected to the CETNA assembly via a conoseal joint. All CETNA assemblies are sealed to the CET columns with Grafoil seals using a

compression collar and a hold down nut with no welds. As shown in the LRA tables, the CETNA are constructed from stainless steel. Based on this supplemental information, the applicant has provided an acceptable basis for concluding that the CETNA assemblies do not need to be within the scope of and managed by the Nickel Alloy Inspection Program because these components do not include any nickel alloy base metal or weld components.

In its response to RAI 3.1.2-1, the applicant also clarified that the only nickel alloy welds associated with the upper RVCH vent nozzles are those nickel alloy welds that join these nozzles to the nickel alloy closure head vent nozzle safe-end. The applicant explained the vent nozzles are carbon steel nozzles with internal stainless steel cladding that are weld to the carbon steel upper RVCH using carbon steel weld materials that have been post weld heat treated. The applicant clarified that the nickel alloy welds associated with the nickel alloy vent nozzle safe ends are within the scope of the applicant's Nickel Alloy Inspection Program. Based on this review, the staff finds that the applicant has provided an acceptable basis for concluding that the upper RVCH head vent nozzle-to-upper RVCH welds do not need to be managed by or be within the scope of either the Nickel Alloy Inspection Program or Reactor Vessel Head Penetration Inspection Program because these components and their associated welds are not fabricated from nickel alloy materials.

Based on this review, the staff finds that the applicant has provided an acceptable basis for managing cracking in these upper RVCH head vent nozzles and CETNA nozzles because: (1) the applicant has clarified which of nozzle designs include nickel alloy base metal or weld materials, (2) the applicant has appropriately credited its Nickel Alloy Inspection Program and Water Chemistry Program to manage cracking in the nickel alloy upper RVCH head vent nozzle safe ends and their nickel alloy safe-end-to-nozzle welds, and (3) in the applicant's AMRs for the CETNA nozzles and upper RVCH head vent nozzles, as given in LRA Tables 3.1.2-IP2-1 and 3.1.2-IP3, the applicant has appropriately credited its Water Chemistry Program and Inservice Inspection Program to manage any cracking that may develop in the components. RAI 3.1.2-1 is resolved and Open Item 3.1.2-1, Part A is closed with respect to the management of cracking in the upper RVCH head vent nozzles and the CETNA nozzles.

The staff verified that the staff's aging management recommendations in GALL AMR IV.D2-4 for primary side steel SG upper and lower heads, tubesheets and tube-to-tubesheet welds with internal stainless steel or nickel alloy cladding is not applicable to the IP2 LRA because the IP2 is currently designed with Model 44F recirculating SGs, and because the staff's guidance in AMR IV.D2-4 is only applicable to once-through SG designs. The staff noted, however, that for these components, the applicant credited its Water Chemistry Control – Primary and Secondary and Steam Generator Integrity Programs to manage cracking due to SCC in the components. The staff noted that this is appropriate for the SG upper and lower heads because the cladding on these components is made from stainless steel and because this is consistent with the staff's recommendations in GALL AMR IV.D2-4 for stainless steel SG cladding that is exposed to the reactor coolant.

The staff noted, however, that the internal cladding for the SG tubesheets is made from nickel alloy material, and that in the LRA, the applicant did not commit to applying any

applicable (1) bulletins and generic letters, and (2) staff-accepted industry guidelines to the any nickel alloy cladding associated with the tubesheets. By letter dated December 18, 2007, in the response to Audit Item 200, the applicant stated that it is committed to implement NRC Orders, bulletins, generic letters, and staff-accepted industry guidelines associated with nickel alloy cladding associated with the SG tubesheets.

Based on this review, the staff finds that the applicant has created an acceptable basis for managing cracking in these nickel alloy components. This is based on the fact that the applicant is crediting the Water Chemistry Program, the Inservice Inspection Program and either the commitment associated with the Nickel Alloy Inspection Program or Reactor Vessel Penetration Inspection Program to manage cracking in the nickel alloy upper RVCH penetration nozzles or housings. In addition, the applicant will use the Water Chemistry Program, Steam Generator Integrity Program, and commitment associated with Nickel Alloy Inspection Program to manage cracking in the nickel alloy SG tubesheet cladding,

(2) LRA Section 3.1.2.2.16 addresses cracking due to SCC that could occur on stainless steel pressurizer spray heads and cracking due to PWSCC that could occur on nickel alloy pressurizer spray heads. The IP pressurizer spray heads are composed of CASS. LRA Section 3.1.2.2.7 item 2 addresses management of cracking for these components.

SRP-LR Section 3.1.2.2.16 states that cracking due to SCC may occur on stainless steel pressurizer spray heads. Cracking due to PWSCC may occur on nickel alloy pressurizer spray heads. The existing program controls water chemistry to mitigate this aging effect. The GALL Report recommends one-time inspection to confirm that cracking has not occurred. For nickel alloy welded spray heads, the GALL Report recommends no further AMR if the applicant complies with applicable NRC orders and commits in the FSAR supplement to implement applicable (1) bulletins and generic letters, and (2) staff-accepted industry guidelines.

The staff verified that in the applicant's AMR on cracking of the IP2 pressurizer spray head, the applicant identifies that the spray heads are made of CASS. Thus, the staff verified that the guidance in SRP-LR Section 3.1.2.2.16 is not applicable to the evaluation of management of cracking in the IP2 and IP3 pressurizer spray heads because the spray heads are not fabricated from nickel alloy materials. The staff 's evaluation of the AMRs for managing cracking of the IP2 and IP3 pressurizer spray heads which are made from CASS materials is documented in Section 3.1.2.2.7, Item (2).

Based on its review, the staff concludes that the applicant's programs, discussed above, meet SRP-LR Section 3.1.2.2.16 criteria for the AMRs that are used to manage cracking in the upper RVCH nozzle tube (i.e., the CRDM penetration nozzles) and housing welds and the SG tubesheet cladding. For the AMR items that apply to LRA Section 3.1.2.2.16, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). Based on this review, the staff has determined that the guidance in SRP-LR Section 3.1.2.2.16.2 is not applicable to the management of cracking in

the IP2 and IP3 pressurizer spray heads because the spray heads are not fabricated from nickel alloy materials. The staff evaluates the applicant's AMRs for managing cracking of the CASS pressurizer spray heads in SER Section 3.1.2.2.7, Item (2).

3.1.2.2.17 Cracking Due to Stress Corrosion Cracking, Primary Water Stress Corrosion Cracking, and Irradiation-Assisted Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.17 against the criteria in SRP-LR Section 3.1.2.2.17.

LRA Section 3.1.2.2.17 addresses cracking due to SCC, PWSCC, and IASCC, stating that they could occur in PWR stainless steel and nickel alloy reactor vessel internals components. To manage cracking for such components, Entergy maintains the Water Chemistry Control – Primary and Secondary Program and will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the staff for review and approval. The applicant's commitment to these programs is in the UFSAR Supplement, LRA Appendix A, Sections A.2.1.41 and A.3.1.41.

SRP-LR Section 3.1.2.2.17 states that cracking due to SCC, PWSCC, and IASCC may occur in PWR stainless steel and nickel alloy reactor vessel internals components. The existing program controls water chemistry to mitigate these aging effects; however, the existing program should be augmented to manage these aging effects for reactor vessel internals components. The GALL Report recommends no further AMR if the applicant commits in the FSAR supplement (1) to participate in the industry programs for investigating and managing aging effects on reactor internals, (2) to evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, to submit an inspection plan for reactor internals to the staff for review and approval.

For Westinghouse-designed reactors, SRP-LR Section 3.1.2.2.17 invokes AMR Item 37 in Table 1 of the GALL Report, Volume 1 and GALL AMR IV.B2-16, IV.B2-20, IV.B2-28, and IV.B2-40, as applicable to the management of cracking due to SCC, PWSCC, or IASCC in Westinghouse RVI lower internals assembly – fuel alignment pins, lower support plate column bolts, and clevis insert bolts; lower internals assembly – lower core plate, radial keys and clevis inserts; RCCA guide tube assemblies – RCCA guide tubes bolts and RCCA guide tubes support pins; and upper internals assembly – upper support column bolts, upper core plate alignment pins, and fuel alignment pins. The staff's aging management recommendations in these GALL-based AMRs is the same as that recommended in SRP-LR 3.1.2.2.17.

The staff verified that, in these AMRs, the applicant credited its Water Chemistry Control Program – Primary and Secondary and LRA Commitment No. 30 to manage cracking of stainless steel and nickel alloy reactor vessel internals components. The staff finds that this is acceptable because it is in conformance with the guidance in SRP-LR Section 3.1.2.2.17 and in the GALL AMRs that are based on this SRP-LR section. The staff also verified that, for these AMRs (and other AMRs on aging management of the RVI components), Entergy has made the applicable commitment for IP2 and IP3 in Commitment 30, which was provided in Entergy letter dated March 24, 2008, and included in UFSAR Supplement Sections A.2.1.41 and A.3.1.41 for