AUDIT SUMMARY REGARDING THE LICENSE RENEWAL APPLICATION FOR THE SHEARON HARRIS NUCLEAR POWER PLANT, UNIT 1

I. Introduction

By letter dated November 14, 2006 (ML0633502670), Carolina Power & Light Company, doing business as Progress Energy Carolinas, Inc., submitted, for the U.S. Nuclear Regulatory Commission's (NRC) review, an application to renew the operating license for the Shearon Harris Nuclear Power Plant (HNP) Unit 1 for an additional 20-year period beyond the end of the current license term of FOL NPF-63. The end of the current license term is October 24, 2026. The license renewal application (LRA) was submitted pursuant to Title 10 of the Code of Federal Regulations Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

In support of the staff's safety review of the LRA for the HNP, an NRC project team from the Division of License Renewal (DLR), Branch C (RLRC), conducted three onsite audits at the HNP site at New Hill, North Carolina, during the weeks of May 21-25, 2007, June 25-29, 2007 and August 13-15, 2007. The project team consisted of staff members from the NRC and engineers from Information Systems Laboratories, Inc. (ISL), RLRC's technical assistance contractor.

The purpose of the onsite audits was to review the aging management programs (AMPs), aging management reviews (AMRs), and time-limited aging analysis (TLAAs) assigned to the project team to ensure compliance with 10 CFR Part 54.

II. Audit and Review Scope

The project team performed its work in accordance with the requirements of 10 CFR Part 54; the guidance provided in Revision 1 of NUREG-1800, Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR); and the guidance provided in Revision 1 of NUREG-1801, Generic Aging Lessons Learned (GALL) Report. Details of how the project team implemented these requirements and guidance are found in the "Audit and Review Plan for Plant Aging Management Programs, Reviews, and Time-Limited Aging Analyses," Docket No. 50-400, (Agencywide Documents Access and Management System (ADAMS), Accession No. ML071270183).

During the onsite audits, the project team reviewed the following HNP AMPs, AMRs, and TLAAs to ensure compliance with 10 CFR Part 54.

<u>AMPs Reviewed</u>

AMPs That are Consistent with the GALL Report

B.2.2 Water Chemistry Program
B.2.4 Boric Acid Corrosion Program
B.2.6 Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program
B.2.10 Open-Cycle Cooling Water System Program

B.2.18 One-Time Inspection Program
B.2.20 Buried Piping and Tanks Inspection Program
B.2.24 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program
B.2.33 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program
B.2.34 Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program
B.2.35 Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program
B.2.36 Metal Enclosed Bus Program
B.2.37 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program
B.3.2 Environmental Qualification (EQ) Program

AMPs That Are Consistent with the GALL Report with Exceptions and/or Enhancements

B.2.1 ASME Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD Program
B.2.3 Reactor Head Closure Studs Program
B.2.5 Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure of Pressurized Water Reactors Program
B.2.7 Flow-Accelerated Corrosion Program
B.2.8 Bolting Integrity Program
B.2.9 Steam Generator Tube Integrity Program
B.2.11 Closed-Cycle Cooling Water System Program
B.2.12 Boraflex Monitoring Program
B.2.13 Inspection of Overhead Heavy Load and Light Load Handling Systems Program
B.2.14 Fire Protection Program
B.2.15 Fire Water System Program
B.2.16 Fuel Oil Chemistry Program
B.2.17 Reactor Vessel Surveillance Program
B.2.19 Selective Leaching of Materials Program
B.2.21 One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program
B.2.22 External Surfaces Monitoring Program
B.2.23 Flux Thimble Tube Inspection Program
B.2.25 Lubricating Oil Analysis Program
B.2.26 ASME Section XI, Subsection IWE Program
B.2.27 ASME Section XI, Subsection IWL Program
B.2.28 ASME Section XI, Subsection IWF Program
B.2.29 10 CFR Part 50, Appendix J Program
B.2.30 Masonry Wall Program
B.2.31 Structures Monitoring Program
B.2.32 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants Program
B.3.1 Reactor Coolant Pressure Boundary Fatigue Monitoring Program

AMPs That Are Not Consistent with or Not Addressed in the GALL Report (Plant-specific programs)

B.2.38 Oil-Filled Cable Testing Program

AMR Results Reviewed

3.1 Reactor Vessel, Internals, and Reactor Coolant System
3.2 Engineered Safety Features Systems
3.3 Auxiliary Systems
3.4 Steam and Power Conversion Systems
3.5 Structures and Component Supports
3.6 Electrical and Instrumentation and Controls

TLAAs Reviewed

4.2 Reactor Vessel Neutron Embrittlement
4.3 Metal Fatigue
4.4 Environmental Qualification of Electrical Equipment
4.5 Concrete Containment Tendon Prestress (not applicable)
4.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis
4.7.1 Turbine Rotor Missile Generation Analysis
4.7.2 Crane Cyclic Analyses
4.7.3 Main and Auxiliary Reservoir Sedimentation Analyses
4.7.4 High Energy Line Break Location Postulation Based on Fatigue Cumulative Usage Factor

In addition to the above, the project team reviewed the final safety analysis report (FSAR) supplement summary descriptions that were provided in the LRA, Appendix A, for the AMPs and TLAAs. The project team verified that the supplements provided a sufficient description of the AMP activities or the TLAA description in accordance with the SRP-LR and required by 10 CFR 54.21(d).

III. Summary

During the onsite audits, Progress Energy representatives provided a brief presentation regarding its operating experience, design features, plant programs, basis documents, and analyses pertaining to the LRA review. The project team reviewed the LRA and various basis documents, conducted several break-out meetings and technical interviews with the Progress Energy personnel, and conducted a walkdown of key plant areas.

During the audit and review, the project team asked 346 questions. These questions and Progress Energy's responses including staff's review are documented in Section VI of this audit summary. Fifty-five of the questions resulted in revisions to the LRA. The applicant amended the LRA and identified 34 Commitments in its letters dated November 14 and August 20, 2007. The applicant's database that contains the question and answers from the NRC audits of the LRA AMPs, AMRs, and TLAAs can be viewed through the ADAMS using Accession Number ML071060390.

Overall, Progress Energy staff provided excellent support to the project team. All of the questions except two were addressed satisfactorily by the applicant at the conclusion of the onsite audits. In question number 302, the project team asked the applicant for clarifications to the TLAAs regarding the evaluation of the design basis thermal transients for Class 1 components. In question number 323, the project team needed additional information to determine the adequacy of aging management of high-voltage oil-filled cable system. The applicant is addressing these questions via the staff's request for additional information (RAIs) 4.3.1-1 and 3.6.2-1, respectively.

Specifically, in RAI 4.3.1-1, the staff requested the applicant to account for all plant transients recorded for the current operating period and to clarify how the recorded cycles were used to project the 60-year values for the transients in LRA Table 4.3-2. In a letter dated April 6, 2007, the applicant stated that a formal response to RAI 4.3.1-1 regarding Class 1 Fatigue will be provided at a later date. The applicant also stated that it is currently performing a detailed review of the original design basis cycle analysis and subsequent analyses. The result of this review will be a report providing the technical details of what methods were used, why the current design basis allowable cycles are appropriate and how JAFNPP intends to address differences between the current allowable number of cycles and the projected number of cycles.

Also, in RAI 3.6.2-1, the staff requested that the applicant provide a technical justification of why an AMP is not required for high-voltage oil-filled cable system or provide a plant-specific AMP that contains the required ten elements to manage its aging effects. In a letter dated April 6, 2007, the applicant provided the final responses addressing the AMPs for the high-voltage oil-filled cable system components.

At the conclusion of the onsite audits, the project team summarized the status of its review to the HNP staff and management. The project team indicated that the review was ongoing and any additional information necessary to support the review after the onsite audits would be formally requested as an RAI.

The results of the onsite audits will be documented in the staff's safety evaluation report related to the HNP LRA to be published on March 18, 2008.

IV. Documents Reviewed

The following is a list of applicant's documents reviewed by the project team, including documents prepared by others for the applicant. Inclusion of a document on this list does not imply that the project team reviewed the entire document, but rather that selected sections or portions of the documents were reviewed as part of the overall effort documented in the staff's safety evaluation report. In addition, inclusion of a document in this list does not imply NRC acceptance of the document.

AMP Review

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
ASME Section XI Inservice Inspection, Subsections IWB,	ASME Section XI Inservice Inspection,	HNP-P/LR-0606, "License Renewal Aging Management Program

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
IWC, and IWD Program (AMP B.2.1)	Subsections IWB, IWC, and IWD, XI.M1	Description of the ASME Section XI, Subsections IWB, IWC and IWD Inservice Inspection Program," Revision 0. Progress Energy Procedure ISI-100, Control of Inservice Inspection and Testing Activities. Progress Energy Procedure HNP-ISI-002, HNP ISI Program Plan - 2nd Interval, Revision 1, May 4, 2005. NRC Order EA-03-009, "Issuance of Order Establishing Interim Inspection Requirements for Reactor Vessel Heads at Pressurized Water Reactors," February 11, 2003. First Revised NRC Order EA-03-009, "Issuance of Order Establishing Interim Inspection Requirements for Reactor Vessel Heads at Pressurized Water Reactors," February 20, 2004. NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," August 3, 2001. CP&L Serial Letter No. HNP-01-124, Response to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," September 4, 2001. CP&L Serial Letter No. HNP-02-009, Supplemental Response to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," January 28, 2002. NRC Bulletin 2002-01, "Reactor

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," March 18, 2002. CP&L Serial Letter No. HNP-02-052, 15-Day Response to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," April 2, 2002. CP&L Serial Letter No. HNP-02-063, 60-Day Response to NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," May 15, 2002. CP&L Serial Letter No. HNP-02-164, Request for Additional Information, NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," January 23, 2003. NRC Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," August 9, 2002. CP&L Serial Letter No. HNP-02-118, 30-Day Response to NRC Bulletin 2002-02, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," September 12, 2002. NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," August 21, 2003. CP&L Serial Letter No. HNP-03-118, 90-Day Response to NRC Bulletin

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," November 13, 2003. CP&L Letter No. HNP-07-015, Shearon Harris Nuclear Plant, Unit 1, Docket No. 50-400/License No. NPF-63, "Inspection and Mitigation of Alloy 82/182 Pressurizer Butt Welds," January 31, 2007.
Water Chemistry Program (AMP B.2.2)	Water Chemistry, XI.M2	HNP-P/LR-0602, "HNP Water Chemistry Program, Volumes 1, 2, and 3," Revision 1. Nuclear Condition Report AR00133756, Tritium Effluent Leakage Limits Exceeded. Nuclear Condition Report AR00074811, Containment Spray Additive Tank NaOH Percent Being Below its TS Limit. Nuclear Condition Report AR00100101, Boric Acid Tank Boron Concentration Trending Down. Nuclear Condition Reports AR00087716, 00082129, and 00081960, RCS Lithium Level and Lithium Removal Controls. Nuclear Condition Report AR00093623, Delays in Reducing RCS O_2 Concentration. HNP Chemistry and Radiochemistry Procedure No. CRC-001, HNP Environmental and Chemistry Sampling and Analysis Program, Revision 45.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		EPRI Report No. TR-1002884, PWR Primary Water Chemistry Guidelines, October 2003. EPRI Report No. TR-102134, PWR Secondary Water Chemistry Guidelines, Revision 3, October 2003. Licensee Event Report No. 91-002-01 for Dresden Nuclear Power Station, Unit 2, Docket No. 50-273, Reactor Head Closure Stud Outside FSAR Allowable for Material Toughness Due to Unknown Cause.
Reactor Head Closure Studs Program (AMP B.2.3)	Reactor Head Closure Studs, XI.M3	HNP-P/LR-0619, "License Renewal Aging Management Program Description of the Reactor Head Closure Studs Program," Revision 1. Regulatory Guide 1.65, Materials and Inspections for Reactor Vessel Closure Studs, October 1973. Progress Energy Procedure ISI-100, Control of Inservice Inspection and Testing Activities. Progress Energy Procedure HNP-ISI-002, HNP ISI Program Plan - 2nd Interval, Revision 1, May 4, 2005.
Boric Acid Corrosion Program (AMP B.2.4)	Boric Acid Corrosion, XI.M10	HNP-P/LR-0601, "License Renewal Aging Management Program Description of the Boric Acid Corrosion Program," Revision 1. Generic Letter (GL) 88-05, Boric Acid Corrosion of Carbon Steel Reactor Coolant Pressure Boundary Components in PWR Plants, March 17, 1988.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		CP&L Letter from L. W. Eury to the NRC Document Control Desk, Boric Acid Corrosion of Carbon Steel Reactor Coolant Pressure Boundary Components in PWR Plants (Generic Letter 88-05), May 27, 1988. NRC Order EA-03-009, Issuance of Order Establishing Interim Inspection Requirements for Reactor Vessel Heads at Pressurized Water Reactors, February 11, 2003. First Revised NRC Order EA-03-009, Issuance of Order Establishing Interim Inspection Requirements for Reactor Vessel Heads at Pressurized Water Reactors, February 20, 2004. NRC Bulletin 2001-01, Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles, August 3, 2001. CP&L Serial Letter No. HNP-01-124, Response to NRC Bulletin 2001-01, Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles, September 4, 2001. CP&L Serial Letter No. HNP-02-009, Supplemental Response to NRC Bulletin 2001-01, Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles, January 28, 2002. NRC Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity, March 18, 2002. CP&L Serial Letter No. HNP-02-052, 15-Day Response to NRC Bulletin

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity, April 2, 2002. CP&L Serial Letter No. HNP-02-063, 60-Day Response to NRC Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity, May 15, 2002. CP&L Serial Letter No. HNP-02-164, Request for Additional Information, NRC Bulletin 2002-01, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity, January 23, 2003. NRC Bulletin 2002-02, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs, August 9, 2002. CP&L Serial Letter No. HNP-02-118, 30-Day Response to NRC Bulletin 2002-02, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs, September 12, 2002. NRC Bulletin 2003-02, Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity, August 21, 2003. CP&L Serial Letter No. HNP-03-118, 90-Day Response to NRC Bulletin 2003-02, Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity, November 13, 2003.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Progress Energy Procedure HNP-ISI-002, HNP ISI Program Plan - 2nd Interval, Revision 1, May 4, 2005. (as it applies to augmented ISI examinations for boric acid leakage) CP&L Letter No. HNP-07-015, Shearon Harris Nuclear Plant, Unit 1, Docket No. 50-400/License No. NPF-63, Inspection and Mitigation of Alloy 82/182 Pressurizer Butt Welds, January 31, 2007.
Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program (AMP B.2.5)	Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors, XI.M11A	HNP-P/LR-0607, "License Renewal Aging Management Program Description of the Nickel-Alloy Penetration Nozzles Welded to the Upper Reactor Vessel Closure Heads of Pressurized Water Reactors Program," Revision 1. EGR-NGC-0005, Engineering Change, Revision 24. EGR-NGGC-0207, Boric Acid Corrosion Control, Revision 1. MRP-48, PWR Material Reliability Program Response to NRC Bulletin 2001-01 Final Report, August 2001. Letter from HNP to NRC, Serial: HNP-01-124, Response to NRC Bulletin 2001-01, September 4, 2001. VM-OJQ, Reactor Vessel and Accessories, Revision 9. HNP-ISI-002, HNP ISI Program Plan – 2nd Interval, Revision 1. ISI-100, Control of Inservice Inspection and Testing Activities, Revision 25.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Progress Energy Alloy 600 Strategic Plan, Revision 0, June 21, 2006.
Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program (AMP B.2.6)	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS), XI.M13	CAP-NGGC-0202, "Operating Experience Program," Revision 9. Final Safety Analysis Report (FSAR), Chapter 17, Section 17.3, "HNP Quality Assurance Program Description." PRO-NGGC-0204, "Procedure Review and Approval," Revision 8. CAP-NGGC-0200, "Corrective Action Program," Revision 16. CAP-NGGC-0201, "Self-Assessment Program," Revision 8. HNP-ISI-002, "HNP ISI Program Plan – 2nd Interval," Revision 1. ISI-100, "Control of Inservice Inspection and Testing Activities," Revision 25. HNP-P/LR-0308, "License Renewal Aging Management Review, Reactor Coolant Pressure Boundary Systems," Revision 0. FSAR 5.2.0, "Integrity of Reactor Coolant Pressure Boundary." Letter from C. I. Grimes (USNRC) to D. Walters (NEI), Subject: "License Renewal Issue No. 98-0030, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components," May 19, 2000. HNP-P/LR-0302, "License Renewal Mechanical Aging Management Review Methodology," Revision 0.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		NUREG/CR-4513, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems," Revision 1. Materials Reliability Program: "Framework and Strategies for Managing Aging Effects in PWR Internals (MRP-134), June 2005.
Flow-Accelerated Corrosion Program (AMP B.2.7)	Flow-Accelerated Corrosion, XI.M17	HNP-P/LR-0603, "License Renewal Aging Management Program Description of the Flow-Accelerated Corrosion Program," Revision 1. Progress Energy, Nuclear Generation Group Standard Procedure EGR-NGGC-0202, Volume 99, Revision 9, Flow-Accelerated Corrosion Monitoring Program. Altran Report No. 11-0300-TR-001, Flow-Accelerated Corrosion Program System Susceptibility Screening, Volume 1, Revision 0, December 2004. Progress Energy Self Assessment CES-99-027, Self Assessment, Flow-Accelerated Corrosion (FAC) Monitoring Program, Harris Nuclear Plant Assessment Performed September 14-15, 1999. EPRI Guideline NSAC-202-R2, Recommendations for an Effective Flow-Accelerated Corrosion Program, April 1999. NRC Bulletin 87-01, Thinning of Pipe Walls in Nuclear Power Plants, November 6, 1987. CP&L Serial Letter No. NLS-87-189, Shearon Harris Nuclear Power Plant, Docket No. 50-400/License

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		No. NPF-63, NRC Bulletin No. 87-01: Thinning of Pipe Walls in Nuclear Power Plants, September 14, 1987. Generic Letter (GL) 89-08, Erosion/Corrosion-Induced Pipe Wall Thinning, May 2, 1989. CP&L Serial Letter No. NLS-89-206, Response to NRC GL 89-08, July 21, 1989. NRC Information Notice 89-53, Rupture of Extraction Steam Line on High Pressure Turbine, November 6, 1987. NRC Information Notice 91-18, High-Energy Piping Failures Caused by Wall Thinning, March 12, 1991. NRC Information Notice 92-35, Higher Than Predicted Erosion/Corrosion in Unisolable Reactor Coolant Pressure Boundary Piping Inside Containment at a BWR, May 6, 1992. NRC Information Notice 93-21, Summary of NRC Staff Observations Compiled During Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs, March 25, 1993. NRC Information Notice 95-11, Failure of Condensate Piping Because of Erosion/Corrosion at a Flow-Straightening Device, February 24, 1995. NRC Information Notice 97-84, Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion, December 11, 1997.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
Bolting Integrity Program (AMP B.2.8)	Bolting Integrity, XI.M18	HNP-LR-0606, "License Renewal Aging Management Description of the ASME Section XI, Subsections IWB, IWC, IWD, Inservice Inspection Program," Revision 0. HNP POM MMM-10, Threaded Fastener Tightening Procedure, Revision 13. HNP-P/LR-0614, "License Renewal Aging Management Program Description of the External Surfaces Monitoring Program," Revision 1. HNP-LR-0618, "License Renewal Aging Management Description of the ASME Section XI, Subsection IWF Inservice Inspection Program," Revision 1. HNP-ISI-002, HNP ISI Program Plan – 2nd Interval, Revision 1. HNP POM ISI-100, Control of Inservice Inspection and Testing Activities, Revision 25. HNP-P/LR-0372, "License Renewal Aging Management Review for Containment Building," Revision 3.
Steam Generator Tube Integrity (AMP B.2.9)	Steam Generator Tube Integrity, XI.M19	HNP-P/LR-0604, "License Renewal Aging Management Program Description of the Steam Generator Tube Integrity Program," Revision 1. 10 CFR 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." EGR-NGGC-0504, "Mechanical Systems Aging Management Review for License Renewal," Revision 7.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		CAP-NGGC-0202, "Operating Experience Program," Revision 9. NGGM-PM-0007, "QA Program Manual," Revision 10. FSAR, Chapter 17, Section 17.3, "HNP Quality Assurance Program Description." CAP-NGGC-0200, "Corrective Action Program," Revision 16. CAP-NGGC-0201, "Self-Assessment Program," Revision 8. EGR-NGGC-0208, "Steam Generator Integrity Program," Revision 0. NEI 97-06, "Steam Generator Integrity Program," Revision 2. EPRI 1003138, "PWR Steam Generator Examination Guidelines," Revision 6. "HNP Technical Specifications," Section 3/4.4.5. "HNP Technical Specification Bases," Section 3/4.4.6. "90-Day Responses to NRC Generic Letter 97-06: Degradation of Steam Generator Internals," March 30, 1998. NRC Generic Letter 97-06: "Degradation of Steam Generator Internals," December 30, 1997. MNT-NGGC-0007, "Foreign Material Exclusion Program," Revision 6. NRG Generic Letter 2004-01:

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		"Requirements for Steam Generator (SG) Tube Inspections," August 30, 2004. 60-Day Response to NRG Generic Letter 2004-01: "Requirements for Steam Generator Tube Inspections," October 28, 2004. "NRC Closeout Letter to Shearon Harris Nuclear Power Plant, Unit 1" – Response to Generic Letter 2004-01: "Requirements for Steam Generator Tube Inspections," (TAC No. MC 4823), May 19, 2005. NRC Generic Letter 2006-01: "Steam Generator Tube Integrity and Associated Technical Specifications," January 20, 2006. HNP-P/LR-0308, "License Renewal Aging Management Review Reactor Coolant Pressure Boundary Systems," Revision 2. NRC Information Notice 2005-09: "Indications in Thermally Treated Alloy 600 Steam Generator Tubes and Tube-to-Tubesheet Welds," April 7, 2005. NRC Information Notice 2005-09: "Steam Generator Tube and Support Configuration," October 27, 2005. 30-Day Response to NRC Generic Letter 2006-01: "Steam Generator Tube Integrity and Associated Technical Specification," HNP-06-029, February 16, 2006. License Amendment Request, "Application for Technical Specification Improvement Regarding Steam Generator Tube Integrity," HNP-06-060, May 23,

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		2006.
Open-Cycle Cooling Water System Program (AMP B.2.10)	Open-Cycle Cooling Water System, XI.M20	HNP-P/LR-0602, "License Renewal Aging Management Program Description of the Open Cycle Cooling Water System Program," Revision 1. PLP-620, Service Water Program (Generic Letter 89-13), Revision 12. EPT-168, Emergency Service Water Intake and Screening Structures Inspection, Revision 7. CRC-155, Chemistry Control of Circulating Water, Service Water and Cooling Tower Basin, Revision 22. OPT-1518, Emergency Service Water Stagnant Area Flushing Monthly Interval at All Times, Revision 8. EPT-250, A Train ESW Flow Verification/Balance, Revision 16. EPT-241, Emergency Service Water Piping Internal Coating Inspection Train A, Revision 4. EPT-249, Emergency Service Water Piping Internal Coating Inspection Train B, Revision 8. EPT-163, Raw Water Systems Inspections and Documentation, Revision 13. MPT-M0091, Heat Exchanger Opening/Closure for NRC Generic Letter 89-13 Inspections, Revision 11. NLS-90-005, Response to NRC

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Generic Letter 89-13, January 16, 1990. Self-Assessment 56308, Generic Letter 89-13 Program Report. EC 54848, Generic Letter 89-13 Test/Inspection Evaluation. Memo from R. Lebitz to GL 89-13 Program Manager, Performance Testing of CCW Heat Exchangers, August 3, 1998. Serial HNP-94-023, Clarification of Commitments Regarding Macroscopic Biological Fouling, April 16, 1996. EC 49074, RFO10 Generic Letter 89-13 Test/Inspection Evaluation.
Closed-Cycle Cooling Water System Program (AMP B.2.11)	Closed-Cycle Cooling Water System, XI.M21	HNP-P/LR-0627, "License Renewal Aging Management Program Description of the Closed-Cycling Cooling Water System Program," Revision 3. CRC-001, HNP Environmental and Chemistry Sampling and Analysis Program, Revision 44. OST-1216, Component Cooling Water System Operability (A-SA and B-SB Pumps in Service) Quarterly Interval Modes 1-2-3-4, Revision 2.1. EPT-054, Essential Services Chilled Water Flow Balancing (Individual Air Handler Throttle Valve Setting), Revision 13. PLP-620, Essential Chilled Water Turbopak Units Quarterly Inspection/ Checks Modes 1-6, Revision 19.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		MPT-M0038, Emergency Diesel Generator Lube Oil Heat Exchanger Inspection and Cleaning, Revision 11. ERC-007, Chemistry Data Tracking and Trending Program, Revision 0. HNP-P/LR-0600, "License Renewal Aging Management Program Description of the Water Chemistry Program," Revision 1.
Boraflex Monitoring Program (AMP B.2.12)	Boraflex Monitoring, XI.M22	HNP-P/LR-0644, "License Renewal Aging Management Program Description of the Boraflex Monitoring," Revision 1. Serial HNP-96-182, Letter from W.R. Robinson, HNP to USNRC, Shearon Harris Nuclear Power Plant, Docket No. 50-400/License No. NPF-63 Response to Generic Letter 96-04 Boraflex Degradation in Spent Fuel Storage Rack, October 24, 1996. EPT-099, Boraflex Integrity Test (Refueling Interval and Four Year Interval) and Boraflex Coupon String Movement, Revision 6. CRC-001, HNP Environmental and Chemistry Sampling and Analysis Program, Attachment 1.2, Revision 43. Serial HNP-05-004, Letter from J. Scarola, HNP to USNRC, Shearon Harris Nuclear Power Plant, Docket No. 50-400/License No. NPF-63. Supplemental Response to NRC Generic Letter 96-04, Boraflex Degradation in Spent Fuel Storage

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Racks, April 25, 2005. AR-132130, Boraflex Degradation of BWR Fuel Storage Racks at HNP.
Inspection of Overhead Heavy Load and Light Load Handling Systems Program (AMP B.2.13)	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems, XI.M23	HNP-P/LR-0628, "License Renewal Aging Management Program Description of the Inspection of Overhead Heavy Load and Light Load (Related To Refueling) Handling Systems," Revision 1. CAP-NGGC-0202, Operating Experience Program, Revision 10. EGR-NGGC-0351, Condition Monitoring of Structures, Revision 13. MMM0-020, POM for Operation, Testing, Maintenance, and Inspection of Cranes and Special Lifting Devices, Revision 47. PM-M0079, POM for Containment Circular Bridge Crane Inspection and Lubrication, Revision 11. PM-M0097, POM for Cask Handling Crane Inspection, Revision 3. FHP-020, POM for Fuel Handling Procedure, Revision 35.
Fire Protection Program (AMP B.2.14)	Fire Protection, XI.M26	HNP-P/LR-0612, "License Renewal Aging Management Program Description of the Fire Protection Program," Revision 1. Action Request Number: 82829, Repair of Underground Mechanical Joints. Action Request Number: 84089, Repair of Underground Mechanical Joints.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Action Request Number: 58976, Damage Thermo-Log Barrier. Action Request Number: 72645, 9 of 16 Thermo-Log Barriers Inoperable. NFPA 25 (1998 Ed.) HNP Fire Protection Monthly KPI Report on Fire System Status, Open Work Orders and Impairments, April 2007. Fire Protection/Safe Shut Down Out of Service Log, May 22, 2007.
Fire Water System Program (AMP B.2.15)	Fire Water System, XI.M27	HNP-P/LR-0611, "License Renewal Aging Management Program Description of the Fire Water System Program," Revision 1.
Fuel Oil Chemistry Program (AMP B.2.16)	Fuel Oil Chemistry, XI.M30	HNP-P/LR-0631, "License Renewal Aging Management Program Description of the Fuel Oil Chemistry Program," Revision 2. ASTM D 1796, Standard Test Method for Water and Sediment in Fuel Oils by the Centrifuge Method, 1997. ASTM Standard D 2276-00, Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling, 2000. ASTM Standard D 2709-96, Standard Test for Water and Sediment in Middle Distillate Fuels by Centrifuge, 1996. ASTM Standard D 4057-95, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, 2000.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		ASTM Standard D 6217-98, Standard Test Method for Particulate Contamination in Middle Distillate Fuels by Laboratory Filtration, 2003. ASTM Standard D 975-81, Standard Specification for Diesel Fuel Oils. ASTM Standard D 975-01, Standard Specification for Diesel Fuel Oils. ASTM Standard D 2276-78, Standard Test Method for Particulate Contaminant in Aviation Fuel by Line Sampling. ASTM Standard D 4057-81, Standard Practice for Manual Sampling of Petroleum and Petroleum Products. CRC-211, Emergency Diesel Generators Fluid Sampling, Revision 18. RST-208, Diesel Fuel Oil Surveillance (Stored Fuel Only) for the Emergency Diesel Engines, Revision 10. CRC-210, Diesel Fire Pump Engine Fluid Chemistry Monitoring, Revision 18. MST-M0006, Emergency Diesel Generator Fuel Oil Tank Inspection, Revision 14. ESR 9800010, Results of the Fuel Oil Tanks Inspection During RFO #7, Revision 0. RST-209, Technical Specification Surveillance of New Diesel Fuel Oil, Revision 16. NGG Specification NCP-G-0001,

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Common Diesel Fuel Oil (Grade 2-D) Testing Specification, Revision 1. CRC-209, Security Building Emergency Diesel Fuel Oil, Revision 5.
Reactor Vessel Surveillance Program (AMP B.2.17)	Reactor Vessel Surveillance, XI.M31	Reviewed by DCI
One-Time Inspection Program (AMP B.2.18)	One-Time Inspection, XI.M32	HNP-P/LR-0632, "License Renewal Aging Management Program Description of the One-Time Inspection Program," Revision 2. CAP-NGGC-0202, Operating Experience Program, Revision 9. ESR 9800010, Revision 0, January 19, 1998.
Selective Leaching of Materials Program (AMP B.2.19)	Selective Leaching of Materials, XI.M33	HNP-P/LR-0633, "License Renewal Aging Management Program Description of the Selective Leaching Program," Revision 1. HNP-P/LR-0301, "Material/ Environmental Aging Effect Tools for License Renewal," Revision 4. EGR-NGGC-0008, Engineering Programs, Revision 6. 0ENP-650, Brunswick Nuclear Plant Engineering Procedure – Selective Leaching Inspection Program, Revision 0.
Buried Piping and Tanks Inspection Program (AMP B.2.20)	Buried Piping and Tanks Inspection, XI.M34	HNP-P/LR-0634, "License Renewal Aging Management Program Description of the Buried Piping and Tanks Inspection Program," Revision 1. CMP-012, Plant Area Excavation and Backfill, Revision 12.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		MMP-002, Installation of Piping and Piping Components, Revision 13. EGR-NGGC-0005, Engineering Change, Revision 24. EST-213, ASME System Pressure Tests for Fuel Oil Piping, Revision 14. CAR-SH-M-030, Specification for General Power Piping, Revision 20.
One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program (AMP B.2.21)	One-Time Inspection of ASME Code Class 1 Small-Bore Piping, XI.M35	HNP-P/LR-0610, "License Renewal Aging Management Program Description of the One-Time Inspection of ASME Code Class 1 Small Bore Piping," Revision 2. PLP-652, ASME Boiler and Pressure Vessel Code, Section XI, 1989 Edition, No Addenda. HNP-ISI-002, HNP ISI Program Plan – 2nd Interval, Revision 1. ISI-100, Control of Inservice Inspection and Testing Activities, Revision 25. HNP Letter Serial NLS-89-008, Inservice Inspection Report, January 12, 1989. TMM-133, SI Thermal Stratification Monitoring Program, Revision 4. NEI 03-08, Guideline for the Management of Materials Issues, May 2003. ADM-SUBS-00005, Industry Group Membership, Revision 3. EPRI Report 1011955, Management of Thermal Fatigue in Normally

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Stagnant Non-Isolated Reactor Coolant System Branch Lines (MRP-146), Final Report, June 2005. 50-255, USNRC Safety Evaluation Report with a Confirmatory Item Related to the License Renewal of Palisades Nuclear Plant, June 2006, (ML061530042). Letter from HNP to NRC, Serial HNP-05-049, Relief Request to Use a Risk-Informed Inservice Inspection Program for Class 1 and 2 Piping Welds, April 27, 2005. Letter from HNP to NRC, Serial HNP-05-093, NRC Response to the Request for Additional Information (RAI) Regarding the Relief Request for the Risk-Informed ISI Program, October 21, 2005. Letter from NRC to NEI, Summary of the License Renewal Telephone Conference Call and Meeting Held Between the U.S. Nuclear Regulatory Commission Staff and the Nuclear Energy Institute License Renewal Task Force, March 6, 2007 (ML070580498). EPRI 1011955 Material Reliability Program Management of Thermal Fatigue in Normally Stagnant Non-Isolable Reactor Coolant System Branch Lines (MRP-146).
External Surfaces Monitoring Program (AMP B.2.22)	External Surfaces Monitoring, XI.M36	HNP-P/LR-0614, "License Renewal Aging Management Program Description of the External Surfaces Monitoring Program," Revision 2. HNP Procedure TMM-117, System Walkdowns and Observations,

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Revision 8. BNP Procedure 0ENP-648, System Monitoring and Walkdowns, Revision 8. BNP-LR-640, Aging Management Program Description of the Systems Monitoring Program, Revision 1. RNP Procedure TMM-104, System Walkdown Procedure, Revision 18. RNP-L/LR-0640, Aging Management Program – Systems Monitoring Program, Revision 6. Final Safety Evaluation Report Related to the License Renewal of the Brunswick Steam Electric Plant, Units 1 and 2, Accession No. ML0608904210, March 2006. NUREG-1785, Safety Evaluation Report Related to the License Renewal of H.B. Robinson Steam Electric Plant, Unit 2, Accession No. ML040200981. TRN-NGGC-0007, Engineering Support Personnel Training/ Qualification Program and Common Qualification Process, Revision 3. ESC0082N, System Engineer Self Study (HNP Specific), Revision 1. FSAR Section 13.2.2, Training for Technical Plant Staff. EGR-NGGC-0010, System and Component Trending Program and System Notebooks, Revision 12. EGR-NGGC-0351, Conditioning Monitoring of Structures,

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Revision 13. Harris Engineering Support Section Assessment, Report File No.: H-ES-99-01 HNAS 99-106, June 4, 1999. Harris Engineering Support Section Assessment, Report File No.: H-ES-01-01 HNAS 01-057, May 30, 2001. Harris Engineering Support Section Assessment, Report File No.: H-ES-03-01 HNAS 03-046, April 23, 2003. Harris Engineering Support Section Assessment, Report File No.: H-ES-05-01. HNAS 05-044, May 13, 2005. AR00156321, H-ES-05-01 Issue 1 – Trending. AR 00156321, Assignment 01, Significant Adverse Condition Investigation Report, April 13, 2005. INPO Event Number 250-020627-1, External Corrosion Control Program Detects Unexpected Corrosion in Carbon Steel Piping, June 27, 2002. Work Order 992505, Repair Corroded Pipe, Flanges, and Bolting. Work Order 992506, Repair Corroded Pipe, Flanges, and Bolting. Work Order 992513, Repair Corroded Pipe, Flanges, and Bolting.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Action Request 00117120, Corrosion of Traveling Screen Baskets. Action Request 00001118, CH/CX System Degradation.
Flux Thimble Tube Inspection Program (AMP B.2.23)	Flux Thimble Tube Inspection, XI.M37	HNP-P/LR-0609, "License Renewal Aging Management Program Description of the Flux Thimble Tube Inspection Program," Revision 0. ESR 9800334, Incore Eddy Current Test Frequency Extension, Revision 0. EPT-114 Test Results for RFO-10 (9/25/2001), (RMS Record Number 2602087). EPT-114 Test Results for RFO-13 (4/13/2006), (RMS Record Number 3461829). EPT-114 Test Results for RFO2 – Reel 90139 Frame 4933. EPT-114 Test Results for RFO3 – Reel 91193 Frame 2958. EPT-114 Test Results for RFO4 – Reel 92293 Frame 4955. EPT-114 Test Results for RFO5 – Reel 94284 Frame 2213. EPT-114 Test Results for RFO6 – Reel 95645 Frame 2295. EPT-114 Test Results for RFO7 – Reel 97254 Frame 1185. SPP-0649T, Temp Procedure for Westinghouse Electric Co. Contract #3382 for Flux Thimble E/C Test FP-RFS 2.3.1 GEN-3, Revision 0.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program (AMP B.2.24)	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, XI.M38	HNP-P/LR-0620, "License Renewal Aging Management Program Description of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program," Revision 2. HNP POM, CMP-003, Protective Coatings, Revision 16. PASSPORT Action Tracking, SAST 26961, Conduct a Self-Assessment of MNT Work Activities, August 2, 2001. PASSPORT Action Tracking, SAST 55286, Conduct an SA of Predictive & Preventative Maint Freq & Type, December 22, 2003. PASSPORT Action Tracking, SAST 80899, Conduct a Self-Assessment of Work Management, January 20, 2004. PASSPORT Action Tracking, SAST 111536, Conduct a Self-Assessment of Work Management Process (Schedule Development), January 17, 2005. EPRI Technical Report 1008035, Expansion Joint Maintenance Guide, Revision 1, Replaces 1003189, Final Report, May 2003. Action Request 00018914, A Condensate Pump Suction Expansion Joint Degraded. Action Request 00019169, Foreign Material in B MSR.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
Lubricating Oil Analysis Program (AMP B.2.25)	Lubricating Oil Analysis, XI.M39	HNP-P/LR-0621, "License Renewal Aging Management Program Description of the Lubricating Oil Analysis Program," Revision 0. MMM-001, Maintenance Conduct of Operations, Revision 48. TMM-114, Predictive Maintenance, Revision 8. PM-M0074, Equipment Lube Oil Sampling, Revision 18. PM-M0094, Lubrication Oil Sampling Special Applications, Revision 13. PM-M0011, Equipment Lubrication, Revision 18. CHE-NGGC-0009, Particle Count in Lubricating Oil, Revision 3.
ASME Section XI, Subsection IWE Program (AMP B.2.26)	ASME Section XI, Subsection IWE, XI.S1	HNP-P/LR-0616, "License Renewal Aging Management Program Description of the ASME Section XI, Subsection IWE Program," Revision 1. EGR-NGGC-0015, Containment Inspection Program, Revision 3. EST-924, General Visual Examination, Revision 2. ISI-100, Control of Inservice Inspection and Testing Activities, Revision 25. HNP-IWE/IWL-001, First Containment Inspection Interval Containment Inspection Program, Revision 0.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		PLP-605, ASME Boiler and Pressure Vessel Code Section XI Repair and Replacement Program, Revision 24.
ASME Section XI, Subsection IWL Program (AMP B.2.27)	ASME Section XI, Subsection IWL, XI.S2	HNP-P/LR-0617, "License Renewal Aging Management Program Description of the ASME Section XI, Subsection IWL," Revision 1. EST-925, ASME Section XI Subsection IWL Visual Inspection, Revision 1. ISI-100, Control of Inservice Inspection and Testing Activities, Revision 25. HNP IWE/IWL, First Containment Inspection Interval Containment Inspection Program, Revision 0. PLP-605, ASME Boiler and Pressure Vessel Code Section XI Repair and Replacement Program, Revision 24. Assessment 178624, Harris In-Service Inspection Program Self-Assessment Report, October 23-26, 2006. Assessment ENG-00-004, Harris ASME Section XI Pressure Testing Program, July 24-26, 2000.
ASME Section XI, Subsection IWF Program (AMP B.2.28)	ASME Section XI, Subsection IWF, XI.S3	HNP-P/LR-0618, "License Renewal Aging Management Program Description of the ASME Section XI, Subsection IWF Program," Revision 1. ISI-200, Safety-Related Component Support (Hangers and Snubbers) Examination and Testing Program, Revision 18.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		PLP-106, Technical Specification Equipment List Program and Core Operating Limits Report, Revision 40. ISI-120, Inservice Inspection Drawing Preparation and Control, Revision 9. ISI-100, Control of Inservice Inspection and Testing Activities, Revision 25. NDEP-0613, VT-3 Visual Examination of Nuclear Power Plant Components, Revision 18. HNP-ISI-002, HNP ISI Program Plan – 2nd Interval, Revision 1. H-ISI-99-01, Harris In-Service Inspection/Testing Assessment Report, September 22, 1999.
10 CFR Part 50, Appendix J Program (AMP B.2.29)	10 CFR 50, Appendix J, XI.S4	HNP-P/LR-0615, "License Renewal Aging Management Program Description of the 10 CFR 50, Appendix J Program," Revision 1. EST-210, Periodic Containment Integrated Leak Rate Testing (Type A Test). EST-209, Type B Local Leak Rate Tests, Revision 15. EST-212, Type C Local Leak Rate Tests, Revision 40. ISI-113, Local Leak Rate Testing Program, Revision 8. EGR-NGGC, Containment Inspection Program, Revision 3.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		Technical Specifications for Shearon Harris Unit 1 NPF-63.
Masonry Wall Program (AMP B.2.30)	Masonry Wall Program, XI.S5	HNP-P/LR-0645, "License Renewal Aging Management Program Description of the Masonry Wall Program," Revision 1. CAP-NGGC-0202, Operating Experience Program, Revision 10. NGGM-PM-0007, QA Program Manual, Revision 11. PRO-NGGC-0200, Procedure Use and Adherence, Revision 8. PRO-NGGC-0204, Procedure Review and Approval, Revision 9. CAP-NGGC-0200, Corrective Action Program, Revision 17. ADM-NGGC-0104, Work Management Process, Revision 29. EGR-NGGC-0351, Condition Monitoring in Structures, Revision 13.
Structures Monitoring Program (AMP B.2.31)	Structures Monitoring Program, XI.S6	HNP-P/LR-0608, "License Renewal Aging Management Program Description of the Structures Monitoring Program," Revision 1. NGGM-PM-0007, QA Program Manual, Revision 10. PRO-NGGC-0200, Procedure Use and Adherence, Revision 7. PRO-NGGC-0204, Procedure Review and Approval, Revision 8. CAP-NGGC-0200, Corrective Action Program, Revision 16.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		ADM-MGGC-0104, Work Management Process, Revision 29. EGR-NGGC-0351, Condition Monitoring of Structures, Revision 13. EPT-811, HNP Dam/Dike/Retaining Wall Monitoring Procedure, Revision 10. TMM-117, System Walkdowns and Observations, Revision 8. CMP-012, Plant Area Excavation and Backfill, Revision 12. EGR-NGGC-0005, Engineering Change, Revision 25. EPT-168, Emergency Service Water Intake and Screening Structures Inspection, Revision 7.
RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants Program (AMP B.2.32)	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, XI.S7	HNP-P/LR-0638, "License Renewal Aging Management Program Description of the RG 1.127, Inspection Of Water-Control Structures Associated With Nuclear Power Plants," Revision 1. NGGM-PM-007, QA Program Manual, Revision 11. PRO-NGGC-0200, Procedure Use and Adherence, Revision 8. PRO-NGGC-0204, Procedure Review and Approval, Revision 9. CAP-NGGC-0200, Corrective Action Program, Revision 17. ADM-NGGC-0104, Work Management Process, Revision 29.

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
		EGR-NGGC-0351, Condition Monitoring of Structures, Revision 13. EPT-811, HNP Dam/Dike Retaining Wall Monitoring Procedure, Revision 10. SHNPP 2005, Water Control Structures Inspection Report, from MACTEC Engineering and Consulting, November 28, 2005. HNP Technical Specification 6.8.4(f), Inspections of Water Control Structures.
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (AMP B.2.33)	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, XI.E1	
Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program (AMP B.2.34)	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits, XI.E2	
Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (AMP B.2.35)	Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, XI.E3	

Applicant's Aging Management Program	GALL Aging Management Program	HNP LRA-AMP Basis Document and Other Documents Reviewed
Metal Enclosed Bus Program (AMP B.2.36)	Metal Enclosed Bus, XI.E4	HNP-P/LR-0638, "License Renewal Aging Management Program Description of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," Revision 1.
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (AMP B.2.37)	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, XI.E6	
Reactor Coolant Pressure Boundary Fatigue Monitoring Program (AMP B.3.1)	Metal Fatigue of Reactor Coolant Pressure Boundary, X.M1	HNP-P/LR-605, "License Renewal Aging Management Program Description of the Reactor Coolant Pressure Boundary Fatigue Monitoring Program," Revision 1. "HNP Operations Management Manual OMM-013, Cycle and Transient Monitoring Program," Revision 15. HNP Technical Support Management TMM-13, "SI Thermal Stratification Monitoring Program."
Environmental Qualification (EQ) Program (AMP B.3.2)	Environmental Qualification (EQ) of Electric Components, X.E1	

AMR Results Review

Applicant's AMR Sections and Systems for HNP	HNP LRA-AMR Basis Document and Other Documents Reviewed
3.1 Reactor Vessel, Internals, and Reactor Coolant System	HNP-P/LR-0101, “License Renewal Mechanical Screening Calculation for Reactor Coolant Systems,” Revision 3. HNP-P/LR-0301, “Material/Environment Aging Effect Tools for License Renewal,” Revision 1. HNP-P/LR-0302, “License Renewal Aging Management Review Methodology,” Revision 0. HNP-P/LR-0307, “License Renewal Further Evaluation Recommended Items,” Revision 1. HNP-P/LR-0606, “ASME Section XI, Subsections IWB, IWC and IWD, Inservice Inspection Program,” Revision 0. HNP-P/LR-0657, “Susceptibility Evaluation of CASS for Thermal Aging Embrittlement,” Revision 0. FSAR 3.9.5, Reactor Vessel Internals (3.9.5.1). FSAR 4.5.1, Control Rod Drive System Structural Materials. FSAR 4.5.2, Reactor Internals Materials. FSAR 5.2.3.2.2, Compatibility of Construction Materials with Reactor Coolant. FSAR 5.3.1, Reactor Vessel Materials. FSAR 5.4.3, Reactor Coolant Piping. FSAR Table 5.2.3-1, Primary and Auxiliary Components Material Specifications. FSAR Table 5.2.3-2, Reactor Vessel Internals Material Specifications. FSAR Table 5.3.1-2, Reactor Vessel Toughness Properties. FSAR Table 5.3.1-7, Reactor Vessel Beltline Region Weld Metal. FSAR 6.2.4.2.4.2, General Design Criterion 55.

Applicant's AMR Sections and Systems for HNP	HNP LRA-AMR Basis Document and Other Documents Reviewed
	5-G-0801, Flow Diagram, Reactor Coolant System, Sheet 2, Revision 21. 5-G-0809, Flow Diagram, Safety Injection System, Sheet 2, Revision 25. Progress Energy, Nuclear Generation Group, Alloy 600 Strategic Plan, Revision 0, June 21, 2006.
3.2 Engineered Safety Features Systems	EGR-NGGC-0504, “Mechanical System Aging Management Review for License Renewal,” Revision 7. HNP-P/LR-0302, “License Renewal Aging Management Review Methodology,” Revision 1. HNP-P/LR-0632, “License Renewal Aging Management Program Description of the One-Time Inspection Program,” Revision 2. CAP-NGGC-0200, Corrective Action Program, Revision 19. CAP-NGGC-0202, Operating Experience Program, Revision 11. OE19585, Fatigue Failure on RHR Pump Root Stop Isolation Valve Socket Weld. OE20677, A Through-Wall Leak Was Discovered in a 1-Inch Pipe Section. OE20885, Cracking of 304 Stainless Steel Safety Injection Accumulator Nozzles and Cracking of the 304 Stainless Steel Cladding (Prairie Island).
3.3 Auxiliary Systems	HNP-P-LR-0301, “Material/Environment Aging Effect Tools for License Renewal,” Revision 4. HNP-P-LR-0308, “License Renewal Aging Management Review for RCP Boundary Systems,” Revision 2. HNP-P-LR-0309, “License Renewal Aging Management Review for ESF Systems,” Revision 2. HNP-P-LR-0310, “License Renewal Aging Management Review for CVCS System,” Revision 3.

Applicant's AMR Sections and Systems for HNP	HNP LRA-AMR Basis Document and Other Documents Reviewed
	HNP-P-LR-0311, “License Renewal Aging Management Review for Diesel Generator, Security Power and Support Systems,” Revision 3. HNP-P-LR-0312, “License Renewal Aging Management Review for Service Water and Related Systems,” Revision 2. HNP-P-LR-0313, “License Renewal Aging Management Review for Component Cooling Water and Chilled Water Systems,” Revision 2. HNP-P-LR-0314, “License Renewal Aging Management Review for Site Fire Protection System,” Revision 2. HNP-P-LR-0315, “License Renewal Aging Management Review for Air and Gas Systems,” Revision 1. HNP-P-LR-0316, “License Renewal Aging Management Review for SFPC and Related Systems,” Revision 1. HNP-P-LR-0317, “License Renewal Aging Management Review for HVAC Systems,” Revision 1. HNP-P-LR-0318, “License Renewal Aging Management Review for Drain Systems,” Revision 3. HNP-P-LR-0319, “License Renewal Aging Management Review for Potable and Demineralized Water Systems,” Revision 2. HNP-P-LR-0320, “License Renewal Aging Management Review for Steam and Power Conversion Systems,” Revision 2. HNP-P-LR-0321, “License Renewal Aging Management Review for Post Accident Hydrogen and Radiation Monitoring Systems,” Revision 1. HNP-P-LR-0322, “License Renewal Aging Management Review for Containment Related Systems,” Revision 1. HNP-P-LR-0323, “License Renewal Aging Management Review for Miscellaneous Systems,” Revision 1. HNP-P-LR-0324, “License Renewal Aging Management Review for Gaseous Waste Processing, Radwaste Sampling and Spent Resin and Concentrates Systems,” Revision 2.

Applicant's AMR Sections and Systems for HNP	HNP LRA-AMR Basis Document and Other Documents Reviewed
	HNP-P-LR-0325, “License Renewal Aging Management Review for Primary and Post Accident Sampling Systems,” Revision 1.
3.4 Steam and Power Conversion Systems	HNP-P/LR-0105, “License Renewal Mechanical Systems Screening Methodology,” Revision 2. HNP-P/LR-0301, “Material/Environment Aging Effect Tools for License Renewal,” Revision 3. AR#73416, Adverse Condition Investigation Form, October 4, 2002. AR#101593, Adverse Condition Investigation Form, August 26, 2003. AR#143023, Significant Adverse Condition Investigation Report, November 7, 2004.
3.5 Structures and Component Supports	HNP-P/LR-0110, “License Renewal Civil Screening for Outside Areas,” Revision 3. HNP-P/LR-0111, “License Renewal Civil Screening for Containment Structures,” Revision 3. HNP-P/LR-0124, “Civil Commodity Types and Bulk Screening of EDB Equipment Types for License Renewal,” Revision 2. HNP-P/LR-0301, “Material Environment Aging Effect Tools for License Renewal,” Revision 4. HNP-P/LR-0370, “Civil Material/Environment Aging Effect Tools for License Renewal,” Revision 1. HNP-P/LR-0371, “License Renewal Civil Aging Management Review for Structures and Components Outside Containment,” Revision 3. HNP-P/LR-0372, “License Renewal/Aging Management Review for Containment Building,” Revision 4.
3.6 Electrical and Instrumentation and Controls	EGR-NGGC-0012, Equipment Data Base, Revision 6. EGR-NGGC-0505, Electrical Component Screening and Aging Management Review for License Renewal, Revision 6. CAP-NGGC-0200, Corrective Action Program, Revision 19.

Applicant's AMR Sections and Systems for HNP	HNP LRA-AMR Basis Document and Other Documents Reviewed
	CAP-NGGC-0201, Operating Experience Program, Revision 9. HNP-P/LR-0300, “Electrical Integrated Plant Assessment,” Revision 2. HNP-P/LR-0301, “Material/Environment Aging Effect Tools for License Renewal,” Revision 0. HNP-P/LR-0301, “Material/Environment Aging Effect Tools for License Renewal,” Revision 1. HNP-P/LR-0664, “License Renewal Aging Management Program Description of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program,” Revision 0. HNP-P/LR-0665, “License Renewal Aging Management Program Description of the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program,” Revision 1. HNP-P/LR-0666, “License Renewal Aging Management Program Description of the Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program,” Revision 1. HNP-P/LR-0667, “License Renewal Aging Management Program Description of the Metal Enclosed Bus Program,” Revision 0. EPRI 1003057, License Renewal Electrical Handbook. EPRI TR-1003471, Bolted Joint Maintenance and Applications Guide, December 2002. EPRI TR-105090, Guidelines to Implement the License Renewal Technical Requirements of 10 CFR 54 for Integrated Plant Assessments and Time-Limited Aging Analyses, November 1995. EPRI TR-109619, Guidelines for the Management of Adverse Localized Equipment Environments, June 1999.

Applicant's AMR Sections and Systems for HNP	HNP LRA-AMR Basis Document and Other Documents Reviewed
	SAND96-0344, Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cable and Terminations, prepared by Ogden Environmental and Energy Services under contract to Sandia National Laboratories for the U.S. Department of Energy, in cooperation with the Electric Power Research Institute, September 1996. CAR-SH-E-004, Isolated Phase Bus Duct, Revision 6. CAR-SH-E-009A, Metal-Enclosed Switchgear 600 Volt Class Drawout Type, Revision 9. CAR-SH-E-014A, 15kV Power Cable, Revision 6. CAR-SH-E-014B, 600V Power & Control Cables and 15kV Power Cables, Revision 10. CPL-HNP1-E-002, Power, Control, Instrumentation and Thermocouple Extension Cable, Revision 1. CPL-HNP1-Z-003, Core Exit Thermocouple Connectors and Cables, Revision 1. Cable List, 6-B-043 S01 C12211A, Revision 0. Cable List, 6-B-043 S01 C12212A, Revision 0. DBD-200, Cable and Raceway Systems, Revision 3. DBD-202, Plant Electrical Distribution System, Revision 9. DBD-303, Excore and Incore Nuclear Instrumentation Systems, Revision 9. DBD-308, Main and Auxiliary Control Boards and Panels, Revision 4. Drawing 6-B-041 0009, 6.9KV Auxiliary Bus 1A, Revision 13. Drawing 6-B-041 0010, 6.9KV Auxiliary Bus 1B, Revision 12. Drawing 6-B-041 0011, 6.9KV Auxiliary Bus 1C, Revision 11. Drawing 6-B-041 0045, 6.9KV Emergency Bus 1A-SA, Revision 12.

Applicant's AMR Sections and Systems for HNP	HNP LRA-AMR Basis Document and Other Documents Reviewed
	Drawing 6-B-051, (all sheets, current revision), Grounding Notes and Details. Drawing 6-G-0052, Station Grounding Plan and Yard Lighting, Revision 12. Drawing 6-G-0029, Main & 6900 Volt Auxiliary One Line Wiring Diagram, Revision 14. Drawing 6-G-0200 S02, (Historical Drawing) Containment Building Sections & Details Sheet 2, Unit 1. Drawing 1364-013109, Cooling Tower Lightning Protection, Revision 4. Drawings 1364-004968, Revision 2, 1364-004969, Revision 3, 1364-005545, Revision 4, 1364-005546, Revision 4, and 1364-020754, Revision 3. 230kV Switchyard Drawings: RE-19265, Revision 22, RE-19267 001, Revision 14, RE-19267 002, Revision 14, RE-19267 003, Revision 7, and RE-19617, Revision 4. HNP-E-0001, Three Hour Fire Rated Cable, Revision 0. VM-QYJ, Bus Isolated Phase, Revision 4. Progress Energy Installation Instructions for Transmission Substation and Line Electrical Connectors (Attachment 18).

TLAA Review

Time-Limited Aging Analyses	HNP Documents Reviewed
4.0 Time-Limited Aging Analyses	HNP-P/LR-0500, “Time-Limited Analysis Identification Calculation,” Revision 3. HNP-P/LR-0502, “Thermal Fatigue Time-Limited Analysis Identification and Evaluation for Reactor Coolant Pressure Boundary Components,” Revision 1. HNP-P/LR-0503, “Thermal Fatigue Time-Limited Analysis Design Input Calculation,” Revision 1.

Time-Limited Aging Analyses	HNP Documents Reviewed
	HNP-P/LR-0505, “TLAA Evaluation for Reactor Coolant Loop Leak-Before-Break Analysis for License Renewal,” Revision 0. HNP-P/LR-0506, “Cyclic Loading That May Not Correspond to Class 1 Design Cycles – Time-Limited Aging Analysis,” Revision 1. HNP-P/LR-0510, “High-Energy Line-Break Postulation Based on Fatigue CUF TLAA,” Revision 0. HNP General Procedure GP-002, Normal Plant Heat from Cold Solid to Hot Subcritical Mode 5 to Mode 3, Revision 38. WCAP-10699, Technical Basis for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Shearon Harris Unit 1, September 2005. WCAP-12639, WOG PZR Surge Line Thermal Stratification Generic Detailed Analysis Program MUHP-1091 Summary Report, June 1990. WCAP-12962, “Structural Evaluation of the H. B. Robinson Unit 2 and Shearon Harris PZR Surge Lines, Considering the Effects of Thermal Stratification,” September 1991. WCAP-13588, Operating Strategies for Mitigating Pressurizer Insurge and Outsurge Transients, March 1993. Advance Change Form for GP-002, Normal Plant Heat from Cold Solid to Hot Subcritical Mode 5 to Mode 3, Revision 6, Effective January 20, 1994, DIN No. 955011313. WCAP-14549-P, Addendum 1, Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Harris Nuclear Plant for the License Renewal Program, Revision 0, January 2005. WCAP-14950, “Mitigation and Evaluation of Pressurizer Insurge/Outsurge Transients, 1998. WCAP-15398, Carolina Power and Light Harris Nuclear Power Plant Steam Generator Replacement/Uprating Analysis and Licensing Project – NSSS Licensing Report, September 2000.

Time-Limited Aging Analyses	HNP Documents Reviewed
	WCAP-15398, Carolina Power and Light Harris Nuclear Power Plant Steam Generator Replacement/Uprating Analysis and Licensing Project – NSSS Licensing Report Supplement 1, December 2001. WCAP-16353-P, “Harris Nuclear Plant Fatigue Evaluation for License Renewal,” Revision 0, January 2005. WCAP-16376-P, “Evaluation of PZR Insurge/Outsurge for Harris Nuclear,” Revision 0, January 2005. CP&L Letter NLS-88-234, Response to NRC Bulletin 88-08, September 28, 1988. CP&L Letter NLS-90-015, Response to NRC Bulletin 88-08, January 26, 1990. PERAS 04-102, Letter form Progress Energy to USNRC, Application for Technical Specification Improvement to Extend the Inspection Interval for Reactor Coolant Pump Flywheels Using the Consolidated Line Item Improvement Process, October 15, 2004. Letter from USNRC to Progress Energy, Issuance of Amendment to Extend the Inspection Interval for Reactor Coolant Interval for Reactor Coolant Pump Flywheels, June 21, 2005. CN-PAFM-04-128, Harris Nuclear Plant 40 for 60 Years Transients Evaluation, Revision 1. CN-PAFM-04-136, Harris License Renewal Piping Environmental Fatigue Evaluations, Revision 0. CN-PAFM-04-143, Harris Nuclear Plant WESTEMS Pressurizer and Surge Line Insurge Outsurge Analysis, Revision 0.

V. Personnel Contacted or Attended NRC Meetings During Onsite Audits

NRC Project Team

Maurice Heath, Team Leader, RLRC
Dave Wrona, Team Leader (AMP Audit), RLRC
K. Robert Hsu, Back-up Team Leader, RLRC
Roy Mathew, Reviewer, RLRC
Farideh Saba, Reviewer, RLRC
Zhian Li, Reviewer, RLRC
Shyam Arora, Reviewer, RLRC
Peter Barbadaro, Reviewer, AFP
Mike Kennedy, Contractor Lead, Reviewer, Information Systems Laboratories, Inc.
Jon Woodfield, Reviewer, Information Systems Laboratories, Inc.
Cliff Marks, Reviewer, Information Systems Laboratories, Inc.

NRC Project Team Support

Kenneth Chang, Chief, RLRC
Robert Hsu, Materials Engineer, RLRC

Applicant Personnel
Roger Stewart, Progress Energy
Barry Schneidman, Progress Energy
Bob Reynolds, Progress Energy
Chris Mallner, Progress Energy
Mike Fletcher, Progress Energy
Mike Heath, Progress Energy
Wayne Bichlmeir, Progress Energy
Richard Eagan, Progress Energy
Steve Talley, Progress Energy

VI. STAFF'S AUDIT QUESTIONS AND APPLICANT'S RESPONSES

A.. Refer to Attachment 1 - Question and Answer Database For AMR and AMP Reviews, Audit and Review Related to the License Renewal Application for Harris Nuclear Power Plant

B. Refer to Attachment 2 - Question and Answer Database For TLAA Reviews, Audit and Review Related to the License Renewal Application for Harris Nuclear Power Plant

Question No. B.2.1-JM-02

REQUEST
The "parameter monitored/inspected" program attribute for HNP basis document HNP-P/LR-0606, "License Renewal Aging Management Program Description of the ASME Section XI, Subsection IWB, IWC and IWD, Inservice Inspection Program," does not identify which aging effects the program monitors for. Clarify which aging effects are within the scope of the "parameter monitored/inspected" program attribute for the ASME Section XI, Subsection IWB, IWC and IWD, Inservice Inspection Program.

RESPONSE
As shown on Attachment 1, page 3 of the basis document, the following aging effects and mechanisms managed by this program are:

Cracking Due to SCC
Loss of Fracture Toughness Due to Thermal Embrittlement
Loss of Material Due to Crevice Corrosion
Loss of Material Due to General Corrosion
Loss of Material Due to Pitting Corrosion
Loss of Material Due to Wear

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has identified which aging effects and mechanisms are within the scope of the “parameter monitored/inspected” program element for its ASME Section XI, Subsection IWB, IWC and IWD, Inservice Inspection Program and because the aging effects that are within the scope of this AMP are consistent with those identified in GALL AMP XI.M1, “ASME Section XI, Subsection IWB, IWC and IWD, Inservice Inspection.” During the NRC audit of the LRA dated June 25-29, 2007, the audit team verified that the scope of the applicant’s ASME Section XI, Subsection IWB, IWC and IWD, Inservice Inspection Program does implement, in part, the general inservice inspection (ISI) requirements that are defined in the ASME Code Section XI, Subsection IWA, and the specific examination for ASME Code Class 1, 2, and 3 components that are required in accordance with the applicable Examination Categories and Inspection Items of the ASME Code Section XI, Tables IWB-2500-1, IWC-2500-1 and IWD-2500-1. This question is resolved.

Question No. B.2.1-JM-04

REQUEST
The "detection of aging effects" program attribute for HNP basis document HNP-P/LR-0606, "License Renewal Aging Management Program Description of the ASME Section XI, Subsection IWB, IWC and IWD, Inservice Inspection Program," does not identify which Non-destructive examination (NDE) methods or visual examination methods are within the scope of the AMP. Clarify which NDE methods and visual examination methods are within the scope of the "detection of aging effects" program attribute for the ASME Section XI, Subsection IWB, IWC and IWD, Inservice Inspection Program. Clarify how the inspection frequencies and sample sizes for the applicable examinations are established.

RESPONSE
NDE methods and visual examination methods within the scope of the "detection of aging effects" program attribute are as specified in the American Society of Mechanical Engineers (ASME) Code, Section XI Subsections IWB, IWC and IWD, Inservice Inspection Program, 1989 Edition. The inspection frequencies and sample sizes for the applicable examinations are established by the American Society of Mechanical Engineers (ASME) Code, Section XI Subsections IWB, IWC and IWD, Inservice Inspection Program, 1989 Edition.

As noted in the description of the NUREG-1801 Section XI.M1 program, 10 CFR 50.55a governs the application of Codes and Standards. In conformance with 10 CFR 50.55a(g)(4)(ii), the ISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that the inspection methods and frequencies for ASME Code Class 1, 2, and 3 components are established by the applicable examination categories defined in the ASME Code Section XI, Subsections IWB, IWC, and IWD. The examinations categories and inspection items in the applicable inspection tables of the ASME Code, Section XI define which type of visual and/or non-destructive examinations are required to be performed on ASME Code Class 1, 2, and 3 components and the frequency for scheduling these examinations. The response also clarifies that the applicant performs the required updates of their ASME Code Section XI Edition pursuant to the applicable requirement in 10 CFR 50.55a. During the audit of June 25-29, 2007, the staff verified that the applicant entered the 4th 10-Year Inservice Inspection Interval for HNP in May of 2007 and that the applicable updated code of record for this interval was the 2001 Edition of the ASME Code Section XI, inclusive of the 2003 Addenda. Thus, the applicant’s exception taken on the Code Edition for their ASME Section XI, Subsection IWB, IWC and IWD, Inservice Inspection Program is no longer necessary, as the updated edition of the code is consistent with the edition of the ASME Code Section recommended in GALL AMP XI.M1. This explanation has been incorporated into the SER assessment for this AMP. This question is resolved.

Question No. B.2.3-JM-01

REQUEST
The "parameter monitored/inspected" program attribute for HNP basis document HNP-P/LR-0619, "License Renewal Aging Management Program Description of the Reactor Head Closure Studs Program," does not identify which aging effects the program monitors for. Clarify which aging effects are within the scope of the "parameter monitored/inspected" program attribute for the Reactor Head Closure Studs Program.

RESPONSE
As shown on Attachment 1, page 1 of the basis document, the following aging effects and mechanisms managed by this program are:

Cracking Due to SCC
Loss of Material Due to Wear

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has identified which aging effects and mechanisms are within the scope of the "parameter monitored/inspected" program attribute for its Reactor Head Closure Studs Program and because the aging effects that are within the scope of this AMP are consistent with those identified in GALL AMP XI.M3, "Reactor Head Closure Studs." The applicant entered the 4th Ten-Year ISI Interval for HNP in May 2007, which will be the interval in effect if the operating license for HNP is extended. The applicable ISI code of record for this interval is the 2001 edition of the ASME Code Section XI, inclusive of the 2003 Addenda. This edition of the ASME Code Section XI is consistent with the edition of the ASME Code Section XI referenced in GALL AMP XI.M3, "Reactor Head Closure Studs," for use. This edition of the ASME Code Section XI includes inspections for reactor vessel closure stud assembly components performed in accordance with the ASME Code Section XI, Table IWB-2500-1, Examination Category B-G-1 and system leakage examinations for the stud assemblies in accordance with Examination Category B-P. Even though system leakage is not categorized as an aging effect, the scope of the Reactor Head Closure Studs Program also includes examinations for leakage, as recommended in GALL AMP XI.M3, "Reactor Head Closure Studs." Based on this review, the staff concluded that the scope of Reactor Head Closure Head Program included activities to comply with the requirements in ASME Code Section XI, Table IWB-2500-1, Examination Categories B-G-1 and B-P and to conform with the recommended program attributes in GALL AMP XI.M3, Reactor Head Closure Studs." This question is resolved.

Question No. B.2.4-ZL-01

REQUEST
The program description section of the Boric Acid Corrosion Program states that this program consists of: (1) visual inspection of external surfaces that are potentially exposed to borated water leakage, (2) timely discovery of leak path and removal of the boric acid residues, (3) assessment of the damage, and (4) follow-up inspection for adequacy of corrective actions.

1. What were HNP's response to the reactor vessel head penetrations leakage and reactor head boric acid corrosion problems occurred at the Davis Besse?

2. Has HNP incorporated NRC communications such as Bulletins, orders, GLs, and INs that are related to the boric acid corrosion problem into the Boric Acid Corrosion Program?

Amend the response to incorporate Bulletins 2003-02 and 2004-01 and HNP's responses to these documents as applicable documents for the BAC program.

RESPONSE
HNP responded to the actions required by NRC generic communications addressing reactor vessel head penetration leakage and issues resulting from the Davis-Besse Nuclear Power Station corrosion problems by providing inspection results, including the results of a bare metal visual inspection of the reactor vessel head via the following correspondence:

1. HNP letter, Serial HNP-97-087: “Response to NRC Generic Letter 97-01,’Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,’” dated April 25, 1997.

2. HNP letter, Serial HNP-97-152: “Response to NRC Generic Letter 97-01,’Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,’” dated July 29, 1997.

3. HNP letter, Serial HNP-99-006: “120 Day Response to NRC Request for Additional Information Regarding Generic Letter 97-01, ‘Degradation of CRDM/CEDM Nozzle and Other Vessel Closure Head Penetrations,’” dated January 26, 1999.

4. HNP letter, Serial HNP-01-124: “Response to NRC Bulletin 2001-01, ‘Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,’” dated September 4, 2001.

5. HNP letter, Serial HNP-02-009: “Supplemental Response to NRC Bulletin 2001-01, ‘Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,’” dated January 28, 2002.

6. HNP letter, Serial HNP-02-052: “15-Day Response to NRC Bulletin 2002-01, ‘Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,’” dated April 2, 2002.

7. HNP letter, Serial HNP-02-063: “60-Day Response to NRC Bulletin 2002-01, ‘Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,’” dated May 15, 2002.

8. HNP letter, Serial HNP-02-164: “Request for Additional Information, Bulletin 2002-01, ‘Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,’” dated January 24, 2003.

9. HNP letter, Serial HNP-02-118: “30-Day Response to NRC Bulletin 2002-02, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs,” dated September 12, 2002.

10. HNP letter, Serial HNP-03-118: “90-Day Response to NRC Bulletin 2003-02, Leakage From Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity,” dated November 13, 2003.

11. HNP letter, Serial HNP-03-070: “Sixty-Day Report in Accordance with NRC Order for Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors, Inspection of RPV Head During Refueling Outage,” dated July 16, 2003.

No boric acid deposits or head degradation have been found due to reactor pressure vessel head penetration nozzle leakage.

Update of Program Based on Generic Communications

The HNP Boric Acid Corrosion Program was implemented in response to Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants." Currently, the program activities are governed by a Corporate, fleet-wide program, and the program manager is responsible for reviewing industry operating experience, such as NRC generic communications, and updating the program as necessary. Through its responses to NRC Bulletins and Orders, HNP has confirmed that the scope of the Boric Acid Corrosion Program, as implemented through plant procedures, has appropriately addressed boric acid leakage detection issues associated with the following:

1. GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations."

2. NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles."

3. NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity." (The response to this Bulletin included a review of the effectiveness of the Boric Acid Corrosion Program at HNP.)

Attachment 1 - Question and Answer Database For AMR and AMP Reviews
Audit and Review Related to the License Renewal Application for
Harris Nuclear Power Plant

Bulletins 2003-02 and 2004-01

Bulletin 2003-02

The NRC issued Bulletin 2003-02 requesting specific information concerning licensees' Reactor Pressure Vessel lower head penetration inspection program. Note: Degradation of nozzles associated with the reactor vessel lower head penetrations has the potential to result in boric acid leakage.

HNP responded to the subject Bulletin via the following correspondence:

> Letter from J. Scarola (PE) to NRC, Serial HNP-03-118: "90-Day Response to NRC Bulletin 2003-02, for Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," dated November 13, 2003.
>
> HNP letter, Serial HNP-04-154: 60-Day Summary Report NRC Bulletin 2003-02, Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity, Request (2), dated January 13, 2005.

Bulletin 2004-01

The NRC issued this bulletin to:

- Advise PWR licensees that current methods of inspecting Alloy 2/182/600 materials may need to be supplemented.
- Request PWR addressees to provide the NRC with information related to the pressurizer penetrations and steam space piping connections materials of fabrication.
- Request PWR licensees to provide the NRC with information related to the inspections performed to ensure that degradation of Alloy 82/182/600 materials will be identified, adequately characterized, and repaired.
- Require PWR addresses to provide a written response to the NRC in accordance with the provisions of Section 50.54(f) of Title 10 of the Code of Federal Regulations (10 CFR 50.54(f)).

HNP responded to the actions required by NRC Bulletin 2004-01 via the following correspondence:

1. HNP letter, Serial HNP-04-097: 60-Day Response to NRC Bulletin 2004-01 for the Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors, July 27, 2004.

2. HNP letter, Serial HNP-04-134: Response to Request for Additional Information Regarding NRC Bulletin 2004-01 for Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors, October 29, 2004.

3. HNP letter, Serial HNP-04-166: 60-Day Report NRC Bulletin 2004-01, Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors, January 14, 2005.

Impact of HNP Correspondence HNP-07-015, January 31, 2007 and HNP-07-026, February 27, 2007 on HNP commitments with respect to Bulletin 2004-01 responses

HNP commitments with respect to Bulletin 2004-01 responses

The actions committed to by Harris Nuclear Plant (HNP) in response to Bulletin 2004-01 are identified in HNP letter, Serial HNP-04-097, dated July 27, 2004. Any other actions discussed in the subject correspondence represent intended or planned actions by HNP. They are described for the NRC's information and are not regulatory commitments.

No.	Commitments	Scheduled Completion Dates
1	HNP will perform bare metal visual inspection exams on the pressurizer penetration and steam space piping connections listed in Table C of letter HNP-04-097 during the next refueling outage (RFO-12) scheduled for the Fall 2004 and during every refueling outage until mitigation is performed, additional guidance is provided by the Materials Reliability Program, or new Code or regulatory requirements are imposed.	RFO-12 (Fall 2004) and every refueling outage per the commitment description.

Impact of HNP Correspondence HNP-07-015, January 31, 2007 and HNP-07-026, February 27, 2007

In October 2006, while performing inspections of pressurizer (PZR) Alloy 82/182 butt welds in accordance with MRP-139, a PWR licensee discovered several circumferential indications in the PZR surge, safety, and relief nozzles. Because of the potential importance of this issue, HNP committed to the following:

No.	Commitments	Scheduled Completion Dates
1	HNP will mitigate the pressurizer Alloy 82/182 butt welds by installing full structural weld overlays on these welds and will inspect post-overlay during refueling outage 14 (RFO-14) in the Fall 2007.	End of RFO-14 (Fall 2007)

Pursuant to discussion with the NRC by phone on February 20, 2007, leakage monitoring described in HNP Correspondence HNP-07-015 is supplemented as described in HNP Correspondence, ML070650468, Serial: HNP-07-026, “Inspection and Mitigation of Alloy 82/182 Pressurizer Butt Welds.” HNP Correspondence HNP-07-026 provides the following original, as well as new or revised commitments:

No.	Commitments	Scheduled Completion Dates
1	HNP will mitigate the pressurizer Alloy 82/182 butt welds by installing full structural weld overlays on these welds and will inspect post-overlay during refueling outage 14 (RFO-14) in the fall 2007.	End of RFO-14 (fall 2007)
2	HNP will monitor unidentified RCS leakage daily while the plant is in Modes 1-3 during stable plant conditions until mitigation of the pressurizer Alloy 82/182 butt welds scheduled in RFO-14 (fall 2007).	Beginning on March 6, 2007 until mitigation of the pressurizer Alloy 82/182 butt welds
3	If unidentified RCS leakage should increase by 0.1 gpm in the daily measurement to the mean, sustained for 72 hours with at least 0.1 gpm not confirmed from sources other than the pressurizer nozzle welds, then the unit will be placed in Mode 3 within six (6) hours and Mode 5 within the next 36 hours, and a bare metal visual inspection of the unmitigated pressurizer surge, spray, safety, and relief nozzle butt welds and safe end butt welds containing Alloy 82/182 material will be performed.	Beginning on March 6, 2007 until mitigation of the pressurizer Alloy 82/182 butt welds

No.	Commitments	Scheduled Completion Dates
4	If unidentified RCS leakage should increase by 0.25 gpm above the baseline, sustained for 72 hours with at least 0.25 gpm not confirmed from sources other than the pressurizer nozzle welds, then the unit will be placed in Mode 3 within six (6) hours and Mode 5 within the next 36 hours, and a bare metal visual inspection of the unmitigated pressurizer surge, spray, safety, and relief nozzle butt welds and safe end butt welds containing Alloy 82/182 material will be performed.	Beginning on March 6, 2007 until mitigation of the pressurizer Alloy 82/182 butt welds
5	HNP will report information of any corrective or mitigative actions taken, and if HNP shuts down due to unidentified RCS leakage (i.e., the action of Response 4 of this letter), then HNP will report bare metal visual inspection results.	Within 60 days of unit restart

Discussion:

Based upon a review of the subject correspondence, no unidentified changes to commitments pursuant to the Bulletin 2004-01 responses were found. The commitments contained in the Bulletin 2004-01 responses are in effect "…until mitigation is performed, additional guidance is provided by the Materials Reliability Program, or new Code or regulatory requirements are imposed." Since the HNP-07-015, January 31, 2007 and HNP-07-026, February 27, 2007 commitments include the mitigation actions committed to in the Bulletin 2004-01 responses, the HNP-07-015, January 31, 2007 and HNP-07-026, February 27, 2007 commitments subsume the actions committed to in the Bulletin 2004-01 responses.

As discussed in NRC Correspondence, Confirmatory Action Letter - Shearon Harris Nuclear Power Plant, Unit No. 1, dated March 22, 2007 (ML070780413):

> "In your letter dated February 27, 2007 (Agencywide Documents Access & Management System (ADAMS) Accession Number ML070650468), you described actions you will take at Shearon Harris Nuclear Power Plant, Unit 1 for the pressurizer dissimilar metal butt welds containing Alloy 82/182 material. These commitments address: 1) completion schedules for inspection/mitigation of the welds; 2) RCS leak monitoring frequency, action levels, and actions; and 3) reporting requirements.
>
> The NRC staff has reviewed these actions and commitments and agrees the actions and commitments are appropriate to address the potential of PWSCC of the applicable pressurizer dissimilar metal butt welds containing Alloy 82/182 material."

Conclusion:

As indicated above, the NRC has reviewed the subject correspondence and agrees the actions and commitments are appropriate to address the potential of PWSCC of the applicable pressurizer dissimilar metal butt welds containing Alloy 82/182 material. Based upon the review of the subject correspondence herein, no unidentified changes to commitments were found.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has: (1) identified the specific HNP responses that have been docketed with respect to applicable NRC generic communications on boric acid corrosion and leakage, (2) clarified that these responses are within the scope of its Boric Acid Corrosion Program, (3) identified the specific commitments that have been made in these responses to augment the boric acid corrosion program, and (4) clarified how the various commitments made on this program inter-relate to one another. Thus, the staff has a clear and sufficient clarification of the augmented activities and commitments that are within the scope of the applicant's program to support the conclusion that AMP B.2.4, "Boric Acid Corrosion Program" is consistent with GALL AMP XI.M10, "Boric Acid Corrosion," and is acceptable. This question is resolved.

Question No. B.2.4-ZL-10

REQUEST
The HNP technical specifications establish the leakage limits for reactor coolant pressure boundary leakage, unidentified RCS leakage, and identified RCS leakage that is not RCPB leakage. Clarify what type of activities or actions are taken to distinguish between these types of leakage upon discovery of RCS leakage, and clarify whether these activities are incorporated into the implementation procedure for the Boric Acid Corrosion Program.

RESPONSE
Attachment 2 to HNP Correspondence, Serial: HNP-07-015, "Shearon Harris Nuclear Power Plant, Unit No. 1 Inspection and Mitigation of Alloy 82/182 Pressurizer Butt Welds," provides a discussion of reactor coolant system (RCS) leakage monitoring. Additionally, HNP FSAR, Section 5.2.5, "Detection of Leakage Through Reactor Coolant Pressure Boundary," provides a detailed discussion of this topic.

Procedures that implement HNP Technical Specification requirements are not considered License Renewal implementing documents because the requirements to perform these activities are associated with the HNP Technical Specifications and will not undergo change without appropriate review.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that the its basis for performing enhanced monitoring for RCS leakage (boric acid leakage) and differentiating between reactor coolant pressure boundary (RCPB) leakage, unidentified RCS leakage, and identified RCS non-pressure boundary leakage is given in CP&L Letter No. HNP-07-015, "Shearon Harris Power Plant, Unit No. 1 Inspection and Mitigation of Alloy 82/182 Pressurizer Butt Welds," dated January 31, 2007 (ADAMS ML0703704050). The applicant amended the letter of January 31, 2007 in CP&L Letter No. HNP-07-026, "Shearon Harris Power Plant, Unit No. 1 Inspection and Mitigation of Alloy 82/182 Pressurizer Butt Welds," dated February 27, 2007 (ADAMS ML0706504681). The letter of January 31, 2007 provided the applicant's programmatic method for performing enhanced system leakage monitoring of its reactor coolant system (RCS), trigger points for taking corrective actions upon detection of RCS leakage, and regulatory commitments for implementing this program. CP&L Letter No. HNP-07-026 provided the applicant's response to NRC expectations (questions) on RCS leakage monitoring and supplemented the commitments in CP&L Letter No. HNP-07-015 with additional commitments on RCS system leakage monitoring and implementation of weld overlays on nickel alloy pressurizer welds that are susceptible to primary water stress corrosion cracking (a source of the leakage if an existing crack were to propagate throughwall). The applicant's response also clarifies that the RCS leakage monitoring is further discussed in FSAR Section 5.2.5.

Regulatory Commitments by CP&L on RCS leakage monitoring from reactor vessel bottom mounted instrumentation nozzles are given in CP&L Letter No. HNP-03-118, "90-Day Response to NRC Bulletin 2003-02, Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," dated November 13, 2003. Consent for regulatory compliance with augmented inspections and augmented RCS leakage monitoring requirements for the HNP upper RV head penetration nozzles is given in CPL Letter No. HNP-03-023, "Shearon Harris Nuclear Power Plant, Unit No. 1, Docket No. 50-400/License No. NPF-63, Twenty-Day Response to Order for Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," as amended in CPL Letter No. HNP-04-045, dated May 9, 2004. These responses provide CP&L's consent to comply with the NRC's augmented inspection and monitoring requirements for upper reactor vessel heads and their penetration nozzles in pressurized water reactors as established in to NRC Order EA-03-009, "Establishing Interim Inspection Requirements for Reactor Pressure Vessel Heads at Pressurized Water Reactors," as

amended by the applicant dated February 11, 2003, and in the NRC's first revision of this Order dated February 20, 2004.

The applicant's response to NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized Water Reactors" (May 28, 2004), is given in CP&L Letter No. HNP-04-097, "60-Day Response to Bulletin 2004-01 for the Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized Water Reactors," dated July 27, 2004. The applicant sent in supplemental responses to Bulletin 2004-01 in CP&L Letter No. HNP-07-015, "Shearon Harris Power Plant, Unit No. 1 Inspection and Mitigation of Alloy 82/182 Pressurizer Butt Welds," dated January 31, 2007 (ADAMS ML0703704050), and in CP&L Letter No. HNP-07-026, "Shearon Harris Power Plant, Unit No. 1 Inspection and Mitigation of Alloy 82/182 Pressurizer Butt Welds," dated February 27, 2007 (ADAMS ML0706504681). The letter of January 31, 2007 provided the applicant's programmatic method for performing enhanced system leakage monitoring of its reactor coolant system (RCS), trigger points for taking corrective actions upon detection of RCS leakage, and regulatory commitments for implementing this program. CP&L Letter No. HNP-07-026 provided the applicant's response to NRC expectations (questions) on RCS leakage monitoring and supplemented the commitments in CP&L Letter No. HNP-07-015 with additional commitments on RCS system leakage monitoring and implementation of weld overlays on nickel alloy pressurizer welds that are susceptible to primary water stress corrosion cracking (a source of the leakage if an existing crack were to propagate throughwall).

Based on this assessment, the staff finds that the applicant has provided a sufficient clarification how the applicant differentiates between RCPB leakage, unidentified RCS leakage, and identified RCS non-pressure boundary leakage. The applicant's responses to pertinent NRC generic communications on RCS leakage from upper RV head penetration nozzles, lower RV head BMI nozzles, and nickel alloy pressurizer components demonstrates that the applicant is implementing augmented RCS leakage monitoring activities from of nickel alloy components located in the reactor coolant pressure boundary.
This question is resolved.

Question No. B.2.8-CM-01

REQUEST
The Bolting Integrity Program identifies that structural and support bolting at HNP does not include any bolting that is considered to be high strength. Identify all materials that are to fabricate bolting at HNP and define the criteria that are used by CPL to screen a particular bolting material in as “high-strength”or “not high-strength.”

RESPONSE
Structural and support bolting materials at HNP subject to license renewal aging management review are available for review at HNP during the upcoming NRC site audits/inspections. As stated in LRA Section B.2.8, the Structures Monitoring Program and the ASME Section XI Inservice Inspection, Subsection IWF Program are credited for aging management of structural bolting.

The criterion used by HNP to screen structural bolting material as "high-strength" is the criterion provided in Section XI.M18 (page XI M-65, element 3) of NUREG-1801 which discusses high strength bolts as having actual yield strength greater than or equal to 150 ksi.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it explains that the Bolting Integrity Program does not have “high-strength” bolting included for aging management. Further, the IWF Program manages structural high-strength bolting. This question is resolved.

Question No. B.2.8-CM-02

REQUEST
Provide additional examples of Bolting Integrity Program operating experience.

RESPONSE
AR 1151 - PLANT LEAK REDUCTION - 05/14/1997

1. Event Description

   Technical Specification 6.8.4 requires that leakage on various systems such as Residual Heat Removal (RHR), Chemical Volume Control System (CVCS), Safety Injection, be reduced to levels which are as low as practical. Review of the work histories on the CVCS and RHR systems indicate that there are numerous bolted joint assemblies (valve to bonnet, flanged valves, flanged heat exchangers, etc.) which have reoccurring leaks. The general repair approach for such leaks is to replace the gasket. Generic guidance is needed to eliminate these repetitive leaks.

2. Action taken

   The following improvements have been made related to leaks at HNP:

   1. Maintenance maintains a leak list which tracks active leaks and develops a schedule for repair. This list is the accountability of the Maintenance Fix It Now (FIN) Team supervisor and FIN Team resources are used to make repairs where possible. As a result, most leak repairs bypass the 12-week scheduling process and are repaired in a relatively short period of time. An exception would be leaks that require an outage to repair or an LCO entry.

   2. Maintenance requires an initiation of an Action Request (AR) for maintenance rework items. Typically rework is defined as re-performance of a corrective maintenance work order within one year of initial repair. The purpose of the AR is to identify corrective actions to prevent rework on the component in the future. This reduces the repetitiveness of repairs.

   3. Engineering has reorganized such that the Rapid Response Team provides component specialists to work with Maintenance to resolve long-standing Maintenance issues. Any leaks with frequent recurrence will be identified to the valve component engineer to identify actions needed to permanently resolve.

Based on the above, current site practices are satisfactory and no additional actions are required.

AR 25929 - Leak in Fire Protection Line near Turbine Building - 05/25/2001

1. Event Description

   Fire pump start was noted with no alarms indicating flow in any building. Operations personnel began a walk down and water was noted coming from the ground on the east side of the turbine building near the deluge valve room. Subsequent to the identification of the leak, the area near the East side of the Turbine building was excavated. The leak was confirmed to be a dislocation of the 12" 90 degree elbow.

2. Cause

   Disassembly of the elbow joint found several of the mechanical flange bolts failed allowing separation of the pipe to elbow joint. Information from the Harris Center Metallurgical Lab review indicated the bolts failed in tension. Engineering review describe the most likely cause being a minor leak at the elbow allowed the immediate area to become softened. Recent work in the area then drove equipment over the location and most probably caused some misalignment. Subsequent pump starts thrust the elbow sufficiently to overstress the bolting and cause a tension failure.

3. Action taken

   Corrective actions include replacement of the failed components, realignment of the installed piping and installation of a thrust block to reduce the load on the elbow during pump starts.

AR 48782 - Three Flange Bolts Missing for Valve 1CW-28 - 09/21/2001

1. Event Description

   Three 2-1/4" diameter bolts were found missing from the lower flange of expansion joint 7CW-J6-1. These bolts are used to attach the lower flange of the expansion joint to the upper body of valve 1CW-28. These three bolts were found missing when personnel were preparing to remove the existing expansion joint.

2. Cause

   These three bolts have evidently been missing since the expansion joints were originally installed. The expansion joint may have been slightly misaligned which caused the female threaded holes in the valve body to be partially obscured. This would have made it very difficult to install the bolts.

3. Action taken

The expansion joint adjacent to valve 1CW-28 was replaced in Refueling Outage 10. At this time the bolt holes were cleaned and found to be suitable for reuse. New bolts were inserted into these holes and torqued to fasten the expansion joint above. The expansion joint is now properly fastened.

AR 84089 - CORRODED FLANGE BOLTS ON UNDERGROUND FIRE SUPPRESSION PIPING - 02/07/2003

1. Event Description

While implementing a work order to excavate a suspected underground leak on the fire protection piping, the 3" piping off the jockey fire pump discharge was found to be leaking at a mechanical joint. Some of the carbon steel bolts used to connect the flanges together were found to be extremely corroded.

2. Cause

Several of the corroded bolts were sent to the Harris Center Metallurgical Lab for failure analysis. The findings were that the bolts had corroded primarily due to a lack of protective coatings. All buried mechanical joints are required to have a protective coating applied. These joints did not appear to have any substantial application of protective coating. The corroded flange bolts were caused by inadequate application of protective coatings during original construction.

3. Action taken

Additional mechanical joints were uncovered during the excavation. All the corroded bolts were replaced. Flanges and rubber seal gaskets were also replaced. After reassembly, all of the mechanical joints were coated prior to backfill of the excavation.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it provided adequate examples of HNP specific bolting experience and the corrective actions taken to correct relevant degradation that has been detected in these bolting components . This question is resolved.

Question No. B.2.10-MK-01

REQUEST
Explain why the Enhancement Section of the AMP stated "None" when the NUREG-1801 Consistency statement for the AMP indicated that the program was an existing program that, following an enhancement, will be consistent with GALL AMP XI.M20. Please provide the enhancement and included in an appropriate license renewal commitment.

RESPONSE
The consistency statement is incorrect. The LRA should read:

> "The Open-Cycle Cooling Water System Program is an existing program that is consistent with NUREG-1801, Section XI.M20."

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that the statement in the LRA is incorrect and has agreed to correct it by amending the LRA to remove “None” from the consistency statement. This question is resolved.

Question No. B.2.10-MK-02

REQUEST
Clarify how injections of chemical additives into the Open Cycle Cooling Water System would provide for sufficient concentrations of additives and adequate aging management in low-flow or stagnant-flow regions of the system.

RESPONSE
The Open-Cycle Cooling Water System Program in LRA Section B.2.10 does not credit the use of chemical treatment alone to ensure proper aging management in stagnant and low flow lines. Per the program's processes and procedures, HNP performs periodic flushing of small bore vents and drains and system flow paths that are not periodically operated. The program also includes periodic inspection and cleaning of large bore system pipelines and intake bays. In addition to periodic flushing of small bore lines, several pipe lines are periodically replaced or will be replaced with stainless steel piping. Finally, as part of the OCCWS Program, HNP uses NDE to manage aging effects in some intermittent flow sections of various size lines in the open-cycle cooling water piping.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that more than chemical additives are employed to deal with the low-flow or stagnant-flow regions of the systems managed by the Open-Cycle Cooling Water Cooling System Program. In fact, the program performs periodic flushing of small bore vents and drains and system flow paths that are not periodically operated. Furthermore, in addition to the periodic flushing of small bore lines, several pipe lines are periodically replaced or will be replaced with stainless steel piping. The program also uses NDE to manage aging effects in some intermittent flow sections of various size lines. On this basis, the staff finds the applicant’s response acceptable. This question is resolved.

Question No. B.2.11-MK-01

REQUEST
LRA Section B.2.11 for the Closed-Cycle Cooling Water System Program describes that some heat exchangers are not monitored for flow, inlet and outlet temperatures, and differential pressure, or from the functionality testing of this program. Identify which closed-cycle cooling water heat exchangers are excluded from the performance-based testing or functionality testing of the AMP, and clarify how the performance and structural integrity of these heat exchangers will be monitored. If other AMPs are credited with these aging management functions, identify which AMPs are credited for aging management of these heat exchangers.

RESPONSE
Flow, temperature and pressure are not specifically monitored in the following Heat Exchangers. As noted in Section B.2.11, in these cases, either the functionality of these heat exchangers is verified by activities outside the Closed-Cycle Cooling Water Program or the specific operating conditions of the heat exchanger render performance testing unreliable.

Primary Sample Condenser and Cooler - The performance of the sample coolers and condensers is validated as the system is used by chemistry personnel. These components are not needed for safe shutdown and not required to mitigate the consequences of an accident.

Component Cooling Water Heat Exchangers - The Component Cooling Water Heat Exchangers are tested/inspected as part of HNP's commitments to Generic Letter 89-13 as described in the Open-Cycle-Cooling Water System Program in B.2.10. An engineering evaluation concluded that factors inherent in the testing process makes the test results too unreliable to be used for operability determinations or as a basis for an inspection program. In addition, temperature and pressures are indicated on the main control board and Operations monitors them to ensure they are performing as expected for the plant conditions.

Emergency Diesel Generator Oil and Jacket Water Coolers - The Emergency Diesel Generator jacket water coolers are tested/inspected as part of HNP's commitments to Generic Letter 89-13 as described in the Open-Cycle-Cooling Water System Program in B.2.10. Inspection and cleaning of the Emergency Diesel Generator Lube Oil Cooler is included as part of a maintenance periodic test. The degradation of heat exchanger performance can be identified through these inspections.

EDG Turbocharger Intercoolers - The combustion air intercoolers are inspected/cleaned as part of periodic diesel generator maintenance. The degradation of heat exchanger performance can be identified through this inspection.

Reactor Coolant Drain Tank Heat Exchanger - The RCDT Heat Exchanger performs no safety related heat transfer function. The heat exchanger tubes provide a pressure boundary function. Nevertheless, high reactor coolant drain tank heat exchanger high temperature is annunciated and the procedural response is to investigate temperature increases that would indicate heat exchanger fouling.

Fuel Pool Heat Exchangers - An engineering evaluation concluded that factors inherent in the testing process make the test results too unreliable to be used for functionality determinations. Degradation of heat exchanger performance can be identified through control room and local alarms. This is considered an exception because specific performance testing is not performed. Per FSAR Section 9.1.3:

> “Control Room and local alarms are provided to alert the operator of high and low pool water level, and high temperature in the fuel pool. A low flow alarm, based on measured flow to the fuel pool, is provided to warn of interruption of cooling flow."
>
> Air Handling Unit Cooling Coils - The safety-related air handling units are periodically inspected and differential pressures recorded. The condition of heat exchanger performance can be identified through this inspection. This is considered an exception because specific performance testing is not performed. Per procedures, Operations performs periodic monitoring of the rooms cooled by these safety-related units.

The licensing renewal activities described above along with the activities described in the Closed-Cycle Cooling Water System Program ensure the performance and structural integrity of these heat exchangers will be maintained during the period of extended of operation.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that there are alternative methods to confirm the functionality of the heat exchangers outside of the Closed-Cycle Cooling Water System Program. These include operating performance characteristics or by monitoring system parameters, including alarm functions. The applicant accounted for all of the heat exchangers that do not receive performance-based or functionality testing. This question is resolved.

Question No. B.2.11-MK-02

REQUEST
The Closed Cycle Cooling Water Program references EPRI TR-107396, Revision 1. The GALL Report recommends Revision 0 of this EPRI report. Describe the process used at HNP to evaluate the incorporation of new industry standards or guidelines into existing plant procedures. Use the incorporation of EPRI TR-107396, Revision 1, into the HNP Environmental and Chemistry Sampling and Analysis Program (CRC-001), as an example.

RESPONSE
HNP and other utilities provide input to as well as reviews of the recommendations of the changes made to EPRI guidelines. EPRI recommended changes are input to the industry operating experience review. As part of this process it is reviewed against the current applicable chemistry program. During this review, manufacturer recommendations or manuals and associated station documents are consulted. Following this review, appropriate changes are made to station chemistry controlling documents such as CRC-001. The change process for this controlling procedure is subject to the safety review process (10 CFR 50.59 process).

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that the implementation of any changes to these procedures is subject to the safety review process. This ensures that the implementation of any potential changes to the acceptance criteria is done in a conservative manner. The staff independently confirmed that the current acceptance criteria in the plant procedure is conservative relative to the Revision 1 of EPRI TR-107396. This question is resolved.

Question No. B.2.12-CM-01

REQUEST
HNP claims consistency with the GALL Report Scope of Program which states that the HNP Boraflex Monitoring Program monitors the effects of aging on the Boraflex panels. This program supports the HNP response to NRC Generic Letter 96-04 (References 5.16 and 5.20) and is implemented by EPT-099, Boraflex Integrity Test. ETP-099 uses coupons that are subject to testing under an accelerated, and long-term frequency. Explain whether there are enough test coupons available to comply with this commitment for the period of extended operation.

RESPONSE
The frequency for test sample removal for long-term surveillance testing is once per four years. There are currently sufficient test coupons in the spent fuel pools to continue testing at this rate throughout the period of extended operation. There are also additional test coupons available in storage tracked through part number 729-786-95. These additional test coupons could be used for future integrity testing after an analysis is put in place to account for the lack of exposure to spent fuel pool conditions.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant described that there are sufficient test coupons installed in the Boraflex spent fuel racks to implement the Boraflex Monitoring Program and because the applicant has identified that there are additional available test coupons in stock that can be placed into service for future testing if the need arises. This question is resolved.

Question No. B.2.12-CM-02

REQUEST
HNP claims consistency with enhancement for Program Element Preventive Action which states that the EPRI Racklife Predictive code will be used. Explain the frequency for running the code. Explain the frequency that data from samples will be input into the racklife program.

RESPONSE
As stated in LRA Section B.2.12, the Boraflex Monitoring Program will be enhanced to incorporate use of the Racklife predictive code, or an equivalent program, into the Boraflex Monitoring Program. Racklife has been used to monitor Boraflex performance and was used to develop information presented in HNP letter to the NRC, dated April 25, 2005; Supplemental Response to NRC Generic Letter 96-04, “Boraflex Degradation in Spent Fuel Pool Storage Racks.” Updates to the Racklife code are not performed on a specified frequency; rather, the Boraflex Monitoring Program will use spent fuel pool silica concentration to initiate an update to the Racklife model.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it stated that Racklife or an equivalent predictive code has been used and will continue to be used to predict Boraflex degradation. Additionally, spent fuel pool silica concentration data, as obtained through spent fuel pool water chemistry sampling and testing and implementation of the applicant’s Water Chemistry Program, will be used to update the Racklife (or equivalent code) model. This question is resolved.

Question No. B.2.12-CM-03

REQUEST
HNP claims consistency with enhancement for Program Element Detection of aging effects which states that the amount of boron carbide released from the Boraflex panel is determined through direct measurement of boron areal density and correlated with the levels of silica present with a predictive code. This is supplemented with detection of gaps through blackness testing and periodic verification of boron loss through areal density measurement techniques such as the BADGER device.

There is no mention of BADGER type testing performed to periodically verify boron loss. Explain what method will be used to perform this.

RESPONSE
The HNP Boraflex Monitoring Program will employ equivalent methods of areal density measurement in addition to blackness testing. This is consistent with the NUREG-1801 program element for Detection of Aging Effects, because it allows "..periodic verification of boron loss through areal density measurement techniques such as the BADGER device." Use of the BADGER device is not mandatory.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it states that although BADGER testing may not specifically be used as an areal density measurement for Boraflex, an equivalent technique would be used. The GALL Report only states that BADGER testing is one type of areal density measurement and that an equivalent test is acceptable. Thus, the information provided by the applicant in response to this question conforms to the staff's recommended program element criteria in GALL AMP XI.M22, "Boraflex Monitoring," for areal density testing. This question is resolved.

Question No. B.2.12-CM-04

REQUEST
HNP claims consistency with enhancement for Program Element Monitoring and Trending which states that the periodic inspection measurements and analysis are to be compared to values of previous measurements and analysis to provide a continuing level of data for trend analysis. Explain whether the enhancement for use of Racklife will be included in the trend analysis.

RESPONSE
The data obtained using the Racklife code is reviewed, recorded, and predicts the degradation of Boraflex over time. The concentration of silica in the spent fuel pools is trended to determine the continued accuracy of the Racklife predictions and to update the Racklife model.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified in its response to Question B.2.12-CM-02 and to this question that it performs periodic sampling and testing of the fuel pool water inventory to monitor for silicate concentration levels, and because the applicant has confirmed in this response that the trending of the silicate concentrations in the fuel pool water will incorporate into its updates of the RACKLIFE code's predictive modeling. This is consistent with the program element criteria in GALL AMP XI.M22, "Boraflex Monitoring," and is acceptable. This question is resolved.

Question No. B.2.13-JW-01

REQUEST

In Harris commitment letter HNP 06-0136 enclosure 1, the commitment 9 enhancements are not consistent with LRA Appendix A.1.1.13 and Appendix B.2.13. Commitment 9 items (5) and (6) are skipped in the numerical sequence. Commitment 9 item (7) is not included in LRA Appendix A.1.1.13 and Appendix B.2.13. Commitment 9 item (4) is not phrased consistent with LRA Appendix A.1.1.13 and Appendix B.2.13. Commitment 9 item (1) is not consistent with the text in LRA Appendix B.2.13. Explain the reasons for these discrepancies.

RESPONSE
HNP LRA Commitment No.9 and Appendix B.2.13 were not consistent with LRA Appendix A.1.1.13 and the basis document. HNP LRA Commitment No.9 and Appendix B.2.13 should be made consistent with LRA Appendix A.1.1.13 and the basis document.

On the basis of this response, HNP-06-0136, Enclosure 1, Harris Nuclear Plant License Renewal Commitments, Commitment No. 9 will be amended to agree with LRA Appendix A.1.1.13 and the basis document, as follows:

> Commitment No. 9, item (7) will be deleted. LRA Appendix B.2.13, Detection of Aging Effects, Item (1) will be changed to state: “to include all cranes that are within the scope of License Renewal.” After these changes, there will be only four (4) enhancement items associated with Harris commitment letter HNP 06-0136, Enclosure 1.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant’s response acceptable because the applicant has explained that LRA Commitment No. 9 and Appendix B.2.13 were not consistent with LRA Appendix A.1.1.13 and the basis document. The applicant stated that it will amend Commitment No. 9 of HNP Commitment Letter HNP-06-0136 Enclosure 1 and LRA Appendix B.2.13 to agree with LRA Appendix A.1.1.13. This question is resolved.

Question No. B.2.16-MK-10

REQUEST
In HNP LRA AMP B.2.20, the statement is made that there are no buried tanks within the scope of license renewal. Why is the buried main tank for the Security Power System diesel engine fuel oil not included within the scope of license renewal and the external surface managed with LRA AMP B.2.20 Buried Tank and Inspection Program?

RESPONSE
Correction, the statement in LRA Section B.2.20 says, “There are no buried tanks in the program.” The buried main tank for the security power system diesel engine fuel oil is within scope and listed in Tables 2.3.3-22 and 3.3.2-22 as buried tanks. In LRA Table 3.3.2-22, the HNP methodology concluded that fiber glass or fiber reinforced plastic buried tank subjected to soil (outside) has no external aging effects. Plant-specific Note 728 describes the details of this tank, it states:

> 728. The buried tank is composed of an inner and outer tank. The exterior surface in contact with soil is made of a self-reinforcing resin (FibreThane) specifically formulated for use in the manufacture of composite storage tanks. The inner shell is steel with no coating. This Air/Gas (Wetted) environment represents the air space inside the fuel oil tanks above the fuel oil level and the air space between the tanks, which is accessible for inspection. The Fuel Oil Chemistry Program and One-Time Inspection Program are appropriate because they include an inspection of the internal surfaces of the tank.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that there are no buried tanks in the program not that there are no buried tanks onsite and that the exterior surface of the outer tank (which is in contact with the soil) is made of self-reinforcing resin (i.e., a fiber glass material). This fiber glass material is not subject to aging effects under exposure to a soil environment. Based on this review, the staff concludes that the Buried Tank and Inspection Program does not need to be credited for the exterior fiber glass surfaces because there are not any associated aging effects for the fiber glass surfaces under exposure to a soil environment. This question is resolved.

Question No. B.2.16-MK-11

REQUEST
The calculation for the Fuel Oil Chemistry Program (HNP-P/LR-0631) has been revised. This revision eliminates one of the exceptions to the GALL Report that was identified in the HNP LRA under the Preventive Actions program element. Please confirm that the LRA will be amended to remove this exception from the application. In addition, provide the proposed revised text to make it clear that this exception has been deleted. Please note in your response that an LRA amendment is required.

RESPONSE
LRA Section B.2.16 will be amended to say:

Under the Program Description section, the sentence starting with "Exposure to fuel oil contaminants…" will be changed to state:

> "Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by verifying the quality of new oil and the addition of a stabilizer, which contains a biocide and corrosion inhibitors before the fuel oil is added to the storage tanks. Subsequently, periodic sampling is performed to assure that the tanks are free of water, particulates, and biological growth."

Under the Exceptions to NUREG-1801 section, for the Preventive Actions, item 1 will be revised to state:

> "A stabilizer containing a biocide and corrosion inhibitor is added to new fuel before it is added to the storage tanks in the Diesel Fuel Oil System and the Security Power System."

Under the Exceptions to NUREG-1801 section, for the Monitoring and Trending element, in the Security Power System discussion in item 2, the paragraph will be revised to state:

> "Security Power System: The Buried Tank and (day) Tank are monitored semiannually not quarterly. This exception is acceptable because operating experience shows no evidence of corrosion or biological growth since the installation of the new tanks, use of the Diesel Grade No 1-D and fuel oil stabilizer containing a biocide and corrosion inhibitors. This covers over ten years of operating experience. If Diesel No. 2-D is used in the future, the monitoring, except for biological growth, will be performed on a quarterly basis for the main storage tank only. (Note: Replacement of the tank was done to comply with more stringent state and federal codes for buried fuel oil tanks.)"

(The revised words for the Program Description above will also replace the second and third sentences in LRA Subsection A.1.1.16.)

A License Renewal Application amendment is required.

STAFF EVALUATION

The staff finds the applicant's response acceptable because the applicant has stated that the LRA will be amended to make it consistent with the basis document for the Fuel Oil Chemistry Program. This amendment will clarify that a stabilizer, which contains a biocide and corrosion inhibitors, is added before the fuel oil is added to the storage tanks. This will remove one of the exceptions to the GALL Report from this program because the applicant's basis will make this aspect of the program consistent with the staff's [preventative actions] program element criteria in GALL AMP XI.M30, "Fuel Oil Chemistry." This question is resolved.

Question No. B.2.16-MK-12

REQUEST
For the Fuel Oil Chemistry Program (B.2.16), please confirm the sampling frequency for the emergency diesel generator and security building diesel generator fuel oil day tanks. Also please provide any necessary enhancements or exceptions related to the sampling of these tanks

RESPONSE
The exceptions and enhancements described in the LRA require revision in order to clarify HNP's position. The Fuel Oil Chemistry Program description in NUREG-1801 addresses the aging management of the Main Fuel Oil Storage Tank. It does not address components downstream of the tank as they are supplied by that fuel oil supply. Since HNP manages the components downstream of the fuel oil storage tank using this program, limited and periodic confirmatory testing is being performed by sampling the fuel oil in the day tanks. Since this testing is not addressed in NUREG-1801, the frequency and testing is not considered an exception.

The LRA will be amended by discussing the confirmatory sampling activity of Fuel Oil Day Tanks in the program description and in the enhancement section Under Monitoring and Trending as described below:

> Fuel Oil System:
> Periodic testing of fuel oil for water and sediment and particulate count is a confirmatory test in EDG day tank and is considered an enhancement. As noted above this sampling is not described in NUREG-1801 and is not considered an exception. Note that the periodic sampling frequency may change with operating experience.
>
> Security Power System:
> The testing for water and sediment and particulate count is a confirmatory test which is already being done semiannually for the Security Diesel day tank. Therefore, this is neither an enhancement nor an exception. Note that the periodic sampling frequency may change with operating experience.

In both of the above systems, the initial frequency will be semiannual. Reference to periodic sampling will be made in the LRA AMP description section and in the FSAR amendment (LRA Appendices A1.16 and B.2.16). The license requirement will take effect prior to the extended period of operation.

Note: There are no commitments being made regarding biological testing in the fuel oil day tanks. Biological testing of fuel oil in the day tank will be performed on a conditional basis only.

A License Renewal Application amendment is required.

STAFF EVALUATION
GALL AMP XI.M30 is silent on chemistry testing for the fuel oil inventories in diesel fuel oil day tanks and therefore does not establish any recommendations on

testing frequencies if an applicant opts to perform testing of fuel oil inventories in day tanks as an augmentation of the AMP. This is acceptable because the applicant will perform periodic the water, sediment, and particulate impurity content testing of oil inventories in the EDG and security oil day tanks and because any such testing is considered to be an augmentation of the AMP. The staff has noted that Harris Technical Specification (TS) 4.8.1.1.2, parts b., c., and d. govern fuel oil chemistry testing and frequency requirements for fuel oil inventories in the EDG fuel oil storage tank and the EDG fuel oil day tanks. The TS requirements for the EDG day tanks only requires periodic testing for water once every 31 days and after each operation of the EDG lasting more than one hour. In spite of these TS requirements, the applicant is proposing sediment and particulate testing of the EDG day tank fuel oil and water, sediment, and particulate testing of the fuel oil in the security diesel fuel oil day tank, which go beyond the recommendations in GALL and the applicant's TS requirements for fuel oil testing. This is conservative to the recommendation in GALL and the applicable TS requirements. Thus, the staff finds the applicant's response to be acceptable because the applicant has adopted a conservative approach to the testing of the fuel oil inventories in the EDG and security fuel oil day tanks, either through the mandated TS requirement in (TS) 4.8.1.1.2, part b. or through an augmentation of the applicant's AMP beyond the recommendations in GALL. This question is resolved.

Question No. B.2.19-CM-01

REQUEST
For Program Element Parameter Monitored/Inspected, HNP describes that the one-time inspection for the initial components will be performed on a representative sampling of components. Describe the methodology used to choose the test population.

RESPONSE
At this time, the methodology for choosing a population has not been decided. HNP is reviewing the latest industry technology used to inspect and evaluate the identification and progression of the selective leaching aging mechanism. HNP will adjust its methods based on an assessment of the effectiveness of the suggested approach or approaches.

For example, development of some level of industry guidance regarding the criteria for visual identification and hardness testing, i.e. EPRI report TR 1013477, Nuclear plant License Renewal Commitments - Utility Implementation Guidance, is scheduled for 2008.

STAFF EVALUATION
The staff's [Detection of Aging Effects] program element criteria in GALL AMP XI.M33, "Selective Leaching of Materials," do not establish what the sample size for the one-time inspection should be. The staff would accept any sample size criterion based on valid industry recommendations (such as those developed by EPRI) to be acceptable for the one-time inspection. Thus, the staff finds the applicant's response acceptable because it explains that the latest industry guidance as well as plant-specific experience will be used to develop the inspection population. This question is resolved.

Question No. B.2.20-MK-01

REQUEST
Is all of the underground piping managed by the Buried Piping and Tank Inspection Program safety related? If not, how are program elements 7, 8, and 9 implemented by the 10 CFR 50 Appendix B Quality Assurance Program?

RESPONSE
No. As stated in LRA Section B.1.3, the elements of corrective action, confirmation process, and administrative controls are common to all AMPs. The program controls and requirements meet the 10 CFR 50, Appendix B requirements. However, they apply to any component within the program regardless of safety class.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has confirmed that the program‘s process and requirements for corrective actions, confirmatory controls, and administrative controls apply to any component within the scope of the program regardless of the safety class of the particular component. This question is resolved.

Question No. B.2.20-MK-02

REQUEST
Clarify whether or not there is any buried cast iron piping within the scope of license renewal. Is so, identify the inspection method that will be employed to detect loss of material due to selective leaching in the buried cast iron piping and clarify whether AMP 2.2.19, "Selective Leaching of Materials Program," or AMP B.2.20, "Buried Piping and Tanks Inspection Program," will be the AMP that is credited for detection of this aging effect.

RESPONSE
Yes, in the Fire Protection System, the buried portion of the fire hydrants, post indicating valves and pipe fittings are made of gray cast iron and are included in the Buried piping, piping components and piping elements Component Commodity shown in LRA Table 3.3.2-27, page 3.3-262. Buried ductile iron piping is evaluated as carbon or low alloy steel as shown on page 3.3-261.

In the Oily Drains System, the portion outside the Diesel Fuel Oil building was evaluated as buried, cast iron piping components and included in the Piping, piping components and piping elements Component Commodity shown in LRA Table 3.3.2-29, page 3.3-297.

Both tables indicate that loss of material due to selective leaching is being managed by the Selective Leaching of Materials Program. In LRA Section B.2.19, the discussion of Scope of Program under Exceptions describes the inspection method that will be employed to detect loss of material due to selective leaching. As noted in this section, Item 2 states that "(2) other mechanical means, i.e., scraping, or chipping, provide an equally valid method of identification" to Brinell hardness testing. This exception has been accepted by the NRC as stated in the "Safety Evaluation Report Related to the License Renewal of the Brunswick Steam Electric Plant, Units 1 and 2," NUREG-1856. This report states on page 3-88:

> “Exception: A qualitative determination of selective leaching will be used in lieu of Brinell hardness testing for components within the scope of this program. The exception involves the use of examinations, other than Brinell hardness testing, identified in GALL AMP XI.M33. The exception is justified, because (1) hardness testing may not be feasible for most components due to form and configuration (i.e., heat exchanger tubes); and, (2) other mechanical means, (i.e., scraping or chipping provide an equally valid method of identification).
>
> The staff reviewed the applicant's exception and determined that it is justified on the following basis: (1) hardness testing is not feasible for most components due to form and configuration; (2) other mechanical means (i.e., resonance when struck by another object, scraping, or chipping) will be used and provide an equally valid method of identification; and, (3) the applicant's program will include one-time inspections and qualitative determinations of selected components that may be susceptible to selective leaching. The staff considered the applicant's justification to be reasonable and acceptable.”

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that for component types susceptible to selective leaching they have also applied the Selective Leaching of Materials Program. The staff confirmed this by reviewing the appropriate AMR results in the LRA. This question is resolved.

Question No. B.2.20-MK-03

REQUEST
In the Buried Piping and Tank Inspection Program, identify the methodology and criteria that will be used to determine locations for inspection based on areas with the highest likelihood of corrosion problems.

RESPONSE
The specific locations and methodology have not been determined. HNP will remain abreast of the Industry with regard to technologies in use and use site and industry Operating Experience reviews and Benchmarking to assist in the selection of an appropriate approach. As described in B.2.20, detailed procedural requirements for the program will be developed. Areas with highest likelihood of corrosion may be identified based on review of site specific operating experience in which degradation has occurred.

HNP will consider using other technologies available to meet its commitments. For example, EPRI is working on a device that could be used for condition Assessment of Large-Diameter Buried Piping (Reference 1). It is envisioned that this technology will scan long sections of piping which provides the advantage of not relying on sampling method. However, the technology is not available and its effectiveness is not known. Structural Integrity Associates has developed a Buried Piping Assessment Program to determine locations that may be suspect (Reference 2). A third approach may involve the review of DC electric current information from HNPs cathodic protection system. It may be used to suggest areas where coating degradation may have occurred.

HNP will base its approach on the effectiveness and cost of the various technologies available.

References:

1) EPRI Report 1011829, "Condition Assessment of Large-Diameter Buried Piping, Phase 2: Vehicle Design and Construction," December 2005.

2) Structural Integrity Associates, Inc. website, <<http://structint.com/images/buriedpipingflyer.html>>.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that, although the specific locations and methodology have not been determined, HNP will remain abreast of the industry technologies and will use industry operating experience reviews with buried piping, HNP-specific operating experience with buried piping, and industry recommendations to assist the applicant in selecting those buried piping and tank locations that are projected to have the highest likelihood of degradation for the one-time inspection. The staff finds this to be acceptable because staff considers generic and plant specific operating experience and valid industry recommendations all to be valid means of assisting the applicant in establishing those components with the highest likelihood of developing degradation, and because this approach is consistent with the [Detection of Aging Effect] criteria in GALL AMP XI.M34, “Buried Piping and Tanks Inspection.” This question is resolved.

Question No. B.2.20-MK-04

REQUEST
The Operating Experience program element for AMP B.2.20, "Buried Piping and Tanks Inspection Program," states that leaks have occurred in some of the buried piping at HNP. Identify the buried piping systems and locations which experienced the degradation, and identify the root cause of the leaks for the degraded buried piping locations. Clarify whether the affected locations were ASME Code Class and how the degraded locations were repaired.

RESPONSE
HNP operating experience reviews have identified that underground piping leaks have occurred.

For non-ASME Code Class pipe:

- An underground leak on the discharge line of the diesel driven fire pump. The one GPM leak originated from a 90 degree elbow mechanical joint. The cause of the leak appears to be differential settlement of the soil backfill supporting the fire line. This leak is not considered age-related degradation.

- The 3-inch piping of the jockey fire pump discharge was found to be leaking at a mechanical joint. Some of the carbon steel bolts used to connect the flanges together were found to be extremely corroded to the extent that the bolts were no longer structurally functional. All mechanical joints are required to have a protective coating applied (such as Flaketar coal tar epoxy). These joints did not appear to have any substantial application of protective coating. Flaketar coating was used on the joint prior to backfill.

  The Site Fire Water System contains piping components that are flanged to underground piping, e.g., hydrants, valves, pipe sections. Similar to other piping components, the bolting is required to have protective coatings, e.g., Flaketar coal tar epoxy. The lack of coating in this case was assumed to be an error of omission as no other failures of this nature have been identified in over 20 years of operation.

- A leak was traced to the 12" fire header on the discharge of the Motor Driven Fire Pump. The leaks were found at two adjacent mechanical joint flanged connections. This leakage at a buried joint was identified and attributed to soil settlement at a flanged connection and is not considered age-related degradation. A contributing factor is that the gasket loses some of its elasticity due to age and hardens. The leaking flanged connections were replaced using new gaskets and new flanges. Gaskets are considered to be subcomponents of the piping and not credited as pressure boundary components. For License Renewal, gaskets are considered to be consumables as discussed in NUREG-1800, Table 2.1-3.

- A potable water line was installed very close to the yard grade, about one foot below the yard surface north of Unit 2. A forklift carrying materials heavier than a normal forklift traveled over this underground piping. The action of the heavy load

movements caused the line to break. This piping leak was due to localized heavy load movements and is not considered age-related degradation.

For ASME Code Class pipe:

- During the 10 year pressure testing of fuel oil system buried piping in Refueling Outage 13, a leak was identified in the diesel fuel oil piping from a main diesel fuel oil storage tank to the day tank. The "A" train piping was unable to hold the required pressure. The leakage was isolated to a section of pipe under the Diesel Generator Building. The section of pipe under the building was abandoned and the underground piping was brought above ground just outside the building. The new piping from the buried line enters the Diesel Generator Building above grade level.

The location of the piping leakage was abandoned in place. The investigation concluded that: “Due to the location of the leak underneath the EDG Building, the pipe section with the leak could not be visually inspected; the apparent cause is a piping through-wall leak caused by exterior corrosion at a location where the coating was either defective or damaged during installation." The subject section of diesel fuel oil piping is ASME Code Class 3.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified either: (1) that the plant-specific operating experience for buried piping has not been the result of age related degradation, or (2) if the operating experience has occurred as a result of aging-related degradation, the applicant has taken appropriate corrective action to correct the adverse condition. With the exception of the operating experience cited for the buried ASME Code Class fuel oil piping, none of the cited operating experience has been in safety-related buried piping or tanks. Currently all of the piping that was used to replace the corroded buried piping is located above ground. Thus, for the degraded piping that got replaced, the applicant has removed the environmental condition inducing the aging effect. This question is resolved.

Question No. B.2.21-SA-01

REQUEST
Are there any socket weld identified as high safety significant locations as part of risk-informed inservice inspection (RI-ISI) program? How does HNP intend to examine socket welds under RI-ISI program?

RESPONSE
There are socket welds currently identified as "high" safety significant locations in RI-ISI.

VT-2 examinations are required to be performed on all Class 1 systems every outage. Currently, HNP performs this examination twice each outage, once at the beginning so we can correct any problems during the scheduled outage, and again as the plant is starting up to meet our ISI commitments. These examinations will include High Safety Significant Class 1 socket welds. HNP will follow Section XI and NRC requirements for socket welds during the period of extended operation.

STAFF EVALUATION
To date, the current state of the art for ultrasonic testing has not developed any transducers that are capable of inspecting small bore socket welds. Thus, the staff's recommendations in GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Piping," were typically written for the inspection of ASME Code Class 1 piping that is welded with full penetration butt welds. To date, the main cause of cracking in small bore socket welds has resulted from high vibration fatigue-induced cracks that penetrate the weld crown (i.e., surface penetrating flaws). For its small bore ASME Code Class 1 socket welds, the applicant is crediting the ASME Section XI visual VT-2 examinations under Examination Category B-P for leakage and the surface examination requirements in ASME Code Section XI under Examination Categories B-F or B-J. The staff finds the applicant's response acceptable because the applicant will follow the ASME Section XI and NRC requirements for examination of socket welds, including the high safety significant ASME Class 1 socket welds during the period of extended operation, and because the ASME Section XI techniques cited by the applicant are capable of detecting these types of surface breaking cracks in the small bore socket weld components. This question is resolved.

Question No. B.2.21-SA-02

REQUEST
How does HNP select sample population and location of piping to be inspected under the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program?

RESPONSE
Consistent with the GALL Report, inspections will be performed at a sufficient number of locations to assure an adequate sample. The sample size for the plant-specific program will be based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small bore piping locations. The sample prioritization will consider the potential for mechanical loading as a result of thermal stratification, piping potentially susceptible to IGSCC (normally stagnant piping), and locations identified for inspection under the RI-ISI program (which considers thermal loading from plant cycles and thermal stratification).

STAFF EVALUATION
The applicant's response indicates that the applicant will use susceptibility, inspectability, dose considerations, operating experience, and limiting locations as the applicant's bases and criteria for selecting a sample of the total population of ASME Code Class 1 small-bore piping for inspection. The staff finds this to be acceptable because the methods used for selecting the ASME Code Class 1 small bore for inspection are consistent with the staff's sample size criteria and bases for selecting locations for inspection, as given in the [Detection of Aging Effects] program element of GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small Bore Piping." This question is resolved.

Question No. B.2.21-SA-03

REQUEST
B.2.21 states that element Monitoring and Trending has an exception to the GALL Report. Basis Document for B.2.21 states that this program element is consistent with the GALL Report with no exceptions. Clarify the discrepancy.

RESPONSE
This discrepancy reflects a minor "cut and paste" error in the conclusion column for the "Monitoring and Trending" program element and the "Detection of Aging Effects" program element. The element evaluations clearly identify the exceptions to the GALL Report which is reflected in the LRA. The basis document will be revised to correct this discrepancy.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant stated that this was an error on its part and will revise the program basis document to correct the discrepancy. The revision of the document will make the program basis document consistent with the program elements in GALL AMP XI.M35, “One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program.” This question is resolved.

Question No. B.2.21-SA-05

REQUEST
Basis Document for B.2.21, element 4-1 states that socket welds receive a VT-2 visual inspection in accordance with the approved ASME Section XI ISI program. ASME Section XI specifies surface examination of socket welds. Clarify the discrepancy.

RESPONSE
ASME Section XI currently requires a pressure test at the end of each refueling outage on all Class 1 socket welds. VT-2 visual examinations are performed at that time. Currently, Section XI requires a surface examination of selected Class 1 socket welds. HNP will follow Section XI and NRC requirements for socket welds during the period of extended operation.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has agreed to perform the surface examination of Class 1 socket welds as required by the ASME Section XI and NRC requirements during the period of extended operation. Refer to the staff's evaluation of audit question B.2.21-SA-01 for additional information. This question is resolved.

Question No. B.2.23-CM-01

REQUEST
Program Element 5, Monitoring and Trending, states that “The wall thickness measurements will be trended and wear rates will be calculated.”

The Monitoring and Trending program element indicates that plant-specific wear results should be used to establish the wear projections for the thimble tubes.

The WCAP-12866 methodology includes using a generic wear rate exponent for predicting wear projections in lieu of using actual plant-specific wear rate data. One of the enhancements for the HNP program calls for CPL to use the generic wear rate exponent in WCAP-12866 for the wear projections if proper justification is made. This not consistent with the GALL Report’s statement that wall-thickness measurements will be trended.

Explain how proposal to use the generic exponential wear value from WCAP-12866 would yield more conservative future wear projections than would be projected if the actual plant-specific wear data were used.

RESPONSE
HNP agrees that allowing a provision to use a generic wear curve exponent is not consistent with the GALL Report. Therefore, LRA Section B.2.23 will be changed to delete statement "If the generic value of 0.67 is used for "n", a basis must be provided for using the generic value in lieu of plant-specific data." Program basis documents will also be revised accordingly and program enhancements, when implemented, will not allow for use of the generic value in lieu of a plant-specific data.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it explains that flux thimble tube generic wear rate will not be used in lieu of a plant-specific value obtained through direct measurement. Further, the applicant stated that they will amend the LRA to delete the potential for the use of the generic value “n” for the wear rate and revise program documentation to reflect this change. This change will make this program consistent with the NRC’s program element criteria in the [Monitoring and Trending] program element of GALL AMP XI.M37, “Flux Thimble Tube Inspection.” This question is resolved.

Question No. B.2.26-JW-01

REQUEST

1) Explain the need for the program enhancements to address surface irregularities, moisture barriers, pressure retaining bolting and augmented examinations.

2) Explain how these four items are addressed or inspected under the current IWE program.

3) Explain if this program has been in compliance with ASME Section XI, Subsection IWE since the final rulemaking to require IWE inspections was made by the NRC in 1996.

4) Explain historically what inspection findings have lead to the need for augmented inspections?

5) Explain if any augmented inspections are currently being performed?

RESPONSE

1) The HNP administrative engineering surveillance test procedure which provides instructions for the general visual examination for ASME Section XI, Subsection IWE does not specifically discuss items such as surface irregularities (for metallic surfaces without coatings), moisture barriers, pressure retaining bolting and augmented examinations. The inspections of these items are however included within the First Containment Inspection Interval Containment Inspection Program document and specific QA inspection documents. The enhancement only improves the administrative procedure by including the instructions for all the IWE inspection requirements into one administrative procedure.

2) The four items are addressed as follows:
Surface irregularities – The HNP administrative engineering surveillance test procedure for the ASME Section XI, Subsection IWE Category E-A, Containment surfaces inspections does not currently list surface irregularities as a specific recordable condition. However, gouges, dents, bulges, and other damage, deformation, or degradation are listed as recordable conditions in the HNP administrative engineering surveillance test procedure and envelopes surface irregularities. The enhancement adds the specific term of “surface irregularities” to the HNP administrative engineering surveillance test procedure. It should also be noted that a QA visual examination form is utilized for inspection of various MC surfaces and it does include “other signs of irregularities” as a specific recordable condition.

Moisture barriers - The inspections of the Category E-D, moisture barrier is performed using a QA visual examination form with the appropriate inspection attributes (wear, damage, erosion, tear, cracks, or other defects). The completed QA visual examination form for the moisture barrier inspections is attached to the administrative engineering surveillance test procedure for the ASME Section XI, Subsection IWE Program as a QA record.

Pressure retaining bolting - The inspections of the Category E-G, Pressure Retaining Bolting is performed using the First Containment Inspection Interval Containment Inspection Program document and a QA visual examination form.

Augmented examinations – An evaluation of the potential Category E-C, Containment Surfaces requiring augmented examination are included as an Appendix to the First Containment Inspection Interval Containment Inspection Program document. However, no areas have been identified as surface areas requiring augmented examination.

3) The program has been in compliance with ASME Section XI, Subsection IWE since the final rulemaking to require IWE inspections was made by the NRC in 1996. The First Containment Inspection Interval for Subsection IWE is defined from September 9, 1998 to September 8, 2008 as described in the HNP Containment Inspection Program Document.

4) The HNP Containment Inspection Program Document provides an evaluation of surfaces likely to experience accelerated degradation and aging. Four areas were identified with the potential for augmented inspections. However, after evaluation, none of the four areas were identified as surface areas requiring augmented examination. The enhancement was provided as a clarification to the administrative procedure, not because there was a need for augmented inspections.

5) No augmented inspections are currently being performed.

STAFF EVALUATION
The staff finds the applicant's response acceptable because (1) the applicant has explained that the program enhancements are only needed to improve the HNP administrative engineering surveillance test procedure by including the instructions for all IWE inspection requirements, (2) the applicant has explained in detail how surface irregularities, moisture barriers, and pressure retaining bolting are inspected and the need for augmented examinations evaluated, (3) the applicant has confirmed that the ASME Section XI, Subsection IWE Program has been in compliance since the final rulemaking was made by the NRC in 1996, (4) the applicant has clarified that there has never been a need for augmented inspections, and (5) the applicant stated that no augmented inspections are currently being performed. This question is resolved.

Question No. B.2.26-JW-02

REQUEST
HNP lists no actual Containment IWE Inservice Inspection findings under operating experience for AMP B.2.26 in the LRA. Provide documentation from discovery to resolution for any historical Containment IWE Inservice Inspection findings.

RESPONSE
A detailed operating experience review was performed and documented in the basis document for the ASME Section XI, Subsection IWE Program and is available for review at HNP. Specific examination reports are also available at HNP for review. The following provides a summary of the findings.

The First Containment Inspection Interval Containment Inspection Program document provides a historical record of Containment inspections prior to the implementation of the IWE Program as discussed below.

Vertical liner corrosion was identified at the interface between the base slab and liner in Refueling Outage 7 (1997). This required partial removal/replacement of the Moisture Barrier. HNP Engineering determined the liner thickness met design requirements and that the deteriorated Moisture Barrier was the root cause. The entire Moisture Barrier was removed during Refueling Outage 8 (1998); the liner was cleaned, the thickness was confirmed to meet design requirements, was coated, and a high density silicone seal Moisture Barrier was installed. The vertical and horizontal liner at the base slab was examined during Refueling Outage 8 and 9 and only minor corrosion was identified. No further actions were required. In addition, the liner plate below the top of the base slab was examined in Refueling Outage 7 after the Moisture Barrier was removed and only minor corrosion was identified. A sample section of liner under the sump topping slab was also examined and no corrosion was identified. In addition, corrosion of the exterior surface of the “A” Containment Spray Valve Chamber due to persistent groundwater intrusion was identified in 1993. However, only minor corrosion was recorded and Ultrasonic Testing (UT) was subsequently performed.

Docketed Letter HNP-00-122, Inservice Inspection Summary Report, To the USNRC from James Scarola, dated October 18, 2000 documents the IWE inspections performed in Refueling Outage 9 (completed 05/12/00). Some recordable indications were observed during the examination but they were determined to be non-relevant by the Responsible Engineer and Program Manager. Conditions observed included coating blisters, mechanical damage to coatings, and discolored coatings on the liner. No significant metal loss was identified in the areas. Some rust and pitting was identified inside the “A” Containment Spray Valve Chamber. The metal thickness however was above nominal thickness as determined by UT. The liner under the transfer canal was identified as bulged but was found acceptable by HNP Engineering with no further action needed. A complete examination of the Containment liner and penetrations, Moisture Barrier, gaskets on applicable penetrations, and penetration bolting was performed.

Docketed Letter HNP-05-018, Inservice Inspection Summary Report, To USNRC from DH Corlett, dated February 15, 2005 documents the IWE inspections performed in RFO-12 (completed 11/15/04). No recordable conditions were identified on the Containment liner from the Moisture Barrier to the center of the dome. A number of non-recordable conditions on the Containment liner were observed such as scattered mechanical damage, blisters with no resulting material loss, and small areas with flaking coatings. A recordable indication of blistering was observed on the protective coating inside the lower regions of each of the valve chambers. No significant material reduction was identified as determined by UT, and the surfaces were recoated. A complete examination of the Containment liner and penetrations, Moisture Barrier, Valve Chamber internals and bolting, Equipment Hatch and the Refueling Access Sleeve was performed.

Docketed Letter HNP-06-081, 90 day Inservice Inspection (ISI) Summary Report, To USNRC from DH Corlett, dated August 10, 2006 documents the IWE inspections performed in RFO-13 (completed 05/16/06). The report states that no examinations of ASME Class MC Components were required or scheduled, but as a prudent measure, examinations of the Moisture Barrier and approximately 12" up from the Moisture Barrier on the liner was performed with no recordable indications observed. The report also states a visual inspection inside the "A" Containment Spray valve chamber including the bolts and nuts on the manway was performed but no recordable conditions were observed. In addition to the report, a visual examination inside the three (3) remaining valve chambers was performed with no recordable conditions observed. One small damaged coating area was repaired in the "A" Containment Spray valve chamber.

STAFF EVALUATION

The staff finds the applicant's response acceptable because the applicant has explained in great detail the documentation available for historical Containment IWE Inservice Inspection findings from initial discovery to resolution of the finding. This question is resolved.

Question No. B.2.26-JW-03

REQUEST
The HNP LRA Appendix B does not have a Protective Coating Monitoring and Maintenance Program section. Please explain how HNP met the intend of GL 98-04, GSI 191, and GL 2004-02?

RESPONSE
Actions taken related to GL 98-04, GSI 191, and GL 2004-02 are part of the current licensing basis; some of these actions remain ongoing.

The NRC issued Generic letter 98-041 to:

1. Alert addressees that foreign material continues to be found inside operating nuclear power plant containments.

2. Alert addressees to problems associated with the material condition of Service Level 1 protective coatings inside the containment.

3. Request information to evaluate the addressees' programs for ensuring that Service Level 1 protective coatings inside containment do not detach from their substrate during a DB LOCA and interfere with the operation of the ECCS and the safety-related CSS.

The HNP November 09, 1992 response to Generic letter 98-04 provided the requested information and this issue was closed out via NRC correspondence dated November 16, 1993.

As discussed in Generic Letter 2004-024, BWR research findings indicated that fibrous material plus particulate material could result in a substantially greater head loss than an equivalent amount of either type of debris alone. These research findings prompted the NRC to open Generic Safety Issue (GSI) 191, "Assessment of Debris Accumulation on PWR Sump Performance." The objective of GSI-191 is to ensure that post-accident debris blockage will not impede or prevent the operation of the emergency core cooling system (ECCS) and containment spray system (CSS) in recirculation mode at PWRs during LOCAs or other HELB accidents for which sump recirculation is required.

In resolution of these issues, Generic Letter 2004-02 requested that addressees take the following actions:

1. Using an NRC-approved methodology, perform a mechanistic evaluation of the potential for the adverse effects of post-accident debris blockage.

2. Implement any plant modifications that the above evaluation identifies as being necessary to ensure system functionality.

Attachment 1 - Question and Answer Database For AMR and AMP Reviews
Audit and Review Related to the License Renewal Application for
Harris Nuclear Power Plant

Generic Letter 2004-02 requested that addressees provide the following information within 90 days of the date of the safety evaluation report providing the guidance for performing the requested evaluation:

1. Information regarding planned actions and schedule to complete the requested evaluation for the adverse effects of post-accident debris blockage.

2. A statement of intent to perform a containment walkdown surveillance in support of the analysis of the susceptibility to the adverse effects of post-accident debris blockage.

This information was provided by HNP correspondence dated March 4, 2005.

Generic Letter 2004-02 further requested that addressees provide the following information by September 1, 2005:

1. Confirmation that the ECCS and CSS recirculation functions under debris loading conditions are or will be in compliance with the regulatory requirements listed in Generic Letter 2004-02.

2. A general description of and implementation schedule for all corrective actions, including any plant modifications.

3. A description of the methodology that was used to perform the analysis for the adverse effects of post-accident debris blockage.

4. A general description of and planned schedule for any changes to the plant licensing bases resulting from any analysis or plant modifications.

5. A description of the existing or planned programmatic controls that will ensure that potential sources of debris introduced into containment will be assessed for potential adverse effects of post-accident debris blockage.

This information was provided by HNP correspondence dated September 01, 2005. Furthermore the September 01, 2005 letter makes the following commitment:

> "Complete the corrective actions of this response letter (HNP-05-101) to Generic Letter (GL) 2004-02 by the GL requested due date of December 31, 2007."

As discussed above, activities related to GL 98-04, GSI 191, and GL 2004-02 are part of the current licensing basis. Corrective actions as described in HNP correspondence dated September 01, 2005 are committed to be complete by December 31, 2007.

1. Generic letter 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant

Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment," July 14, 1998.

2. 120-Day Response to NRC Generic Letter 98-04. "Potential For Degradation of the Emergency Core Cooling System and the Containment Spray System After A Loss-Of-Coolant Accident Because of Construction and Protective Coating Deficiencies And Foreign Material In Containment", Serial HNP-98-155, November 09, 1998.

3. Completion of Licensing Action For Generic Letter 98-04, - "Potential For Degradation Of The Emergency Core Cooling System and the Containment Spray System After A Loss-Of Coolant Accident Because Of Construction And Protective Coating Deficiencies and Foreign Material In Containment" Shearon Harris Nuclear Power Plant, Unit 1, (TAC NO. MA4053), November 16, 1999.

4. Generic Letter 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors," September 13, 2004.

5. Generic Safety Issue 191, "Assessment of Debris Accumulation on PWR Sump Performance."

6. Response to NRC Generic Letter 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors," PE&RAS-05-008, March 4, 2005.

7. Response to NRC Generic Letter 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors," HNP-05-101, September 01, 2005.

STAFF EVALUATION

The staff finds the applicant's response acceptable because the applicant has explained in great detail how it responded to and addressed the NRC's issues and concerns identified in GL 98-04, GSI 191, and GL 2004-02. This question is resolved.

Question No. B.2.26-JW-04

REQUEST
In Basis document HNP-P/LR-0616 an exception is taken to the GALL AMP XI.S1 Program element Scope of Program. In Section 7.3.1 of HNP-P/LR-0616 the following statement is made in discussing the exception to the AMP Scope of Program element: In conformance with 10 CFR 50.55a(g)(4)(ii), the ISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval. This statement has been omitted from the HNP LRA on page B-76 where the exception to the Scope of Program element is discussed for the ASME Section XI, Subsection IWE Program. Explain why this statement was omitted from the LRA exception discussion and if it is applicable.

RESPONSE
The requirement of 10 CFR 50.55a to update the ISI Program during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified 12 months before the start of the inspection interval was inadvertently not repeated in the LRA, because of an oversight. This update is required by NRC regulatory requirements and is applicable to the ASME Section XI, Subsection IWE Program.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that the requirement of 10 CFR 50.55a to update the ISI Program during each successive 120 month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified 12 months before the start of the inspection interval was inadvertently not repeated in the LRA because of an oversight. The applicant stated that it will amend LRA Appendix B.2.26 to correct the oversight. This question is resolved. This is also acceptable because the staff delineated this approach to Code updates on page A.2.11-1 in Table A.2.11, "Dispostion of NEI Comments on Chapter XI.M of the GALL Report," of NUREG-1832 and in pages 53049 - 53050 of the Federal Register, Volume 65, No. 170 (August 31, 2000).

Question No. B.2.27-SA-01

REQUEST
The applicant states that the program is credited for the aging management of accessible and inaccessible pressure retaining primary containment. Are coated areas included under this program? If yes, please describe which coated areas are examined.

RESPONSE
The accessible exterior surfaces of the Containment cylinder wall and base mat where it is enclosed within the Reactor Auxiliary Building and the Fuel Handling Building are generally coated with Service Level II coatings with a few exceptions (such as at high or locked high radiation areas, and at the Main Steam Tunnel). These accessible coated surface areas are examined by the IWL Program. Coating degradation on concrete surfaces is not one of the required inspection attributes in the administrative procedure for the IWL Program because coating degradation does not affect the structural integrity or leak tightness of the Containment. However, according to the administrative procedure for the IWL Program, the VT examiners are encouraged to note all degraded or unusual conditions even if they do not affect the structural integrity or leak tightness of the Containment. The basis document for the IWL Program development stated the condition of the coating can be an indicator of distress and/or degradation of the concrete and that coating degradation should be investigated to assist in the determination of whether distress and/or degradation of the concrete is present. A review of the actual IWL program inspection results from 2001 show coating degradation is identified and evaluated by HNP Engineering.

STAFF EVALUATION
The recommendations in GALL AMP XI.S2, “ASME Section XI, Subsection IWL,” do not specifically address inspections of coatings unless (as specified in the [preventative actions] program element of the GALL AMP) a specific coating program for concrete surfaces is credited as a preventative management program activity. Thus, the applicant’s ASME Code IWL Program goes beyond the recommendations of GALL AMP XI.S2 because, while the applicant does not have a specific coating management program, it is using the coating inspections as an additional indicator of problems in the concrete containment structure. Thus, the staff finds the applicant's response acceptable because the applicant states that the accessible coated areas are examined under the ASME Section XI, Subsection IWL Program and that any relevant indications in the coating can be indicators of the degradation of the concrete and are used to initiate corrective actions in order to prevent any further degradation of concrete. This question is resolved.

Question No. B.2.27-SA-02

REQUEST
In Basis document HNP-P/LR-0617, an exception is taken to the GALL AMP XI.S2 Program element Scope of Program. In Section 7.3.1 of HNP-P/LR-0617 the following statement is made in discussing the exception to the AMP Scope of Program element: In conformance with 10 CFR 50.55a(g)(4)(ii), the ISI Program is updated during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval. This statement has been omitted from the HNP LRA on page B-79 where the exception to the Scope of Program element is discussed for the ASME Section XI, Subsection IWL Program. Explain why this statement was omitted from the LRA exception discussion and if it is applicable.

RESPONSE
The requirement of 10 CFR 50.55a to update the ISI Program during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval was inadvertently not repeated in the LRA, because of an oversight. This update is required by NRC regulatory requirements and is applicable to the ASME Section XI, Subsection IWL Program.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has agreed to amend the LRA to meet the requirements of 10 CFR 50.55a(g)(4)(ii) and will update the ISI Program during each successive 120-month inspection interval to comply with the requirements of the latest edition and addenda of the Code specified twelve months before the start of the inspection interval which also applies to the period of extended operation. This will meet the NRC regulatory requirements of complying with the use of code editions per 10 CFR 50.55a. This is also acceptable because the staff delineated this approach to Code updates on page A.2.11-1 in Table A.2.11, “Dispostion of NEI Comments on Chapter XI.M of the GALL Report,” of NUREG-1832 and in pages 53049 - 53050 of the Federal Register, Volume 65, No. 170 (August 31, 2000).

Question No. B.2.28-SA-01

REQUEST
In program description of LRA, applicant states that program procedures provide for visual examinations of ISI Class 1, 2, and 3 supports. Please justify for not including ASME Class MC supports under this program.

RESPONSE
There are no ASME Class MC supports at HNP as discussed in the First Containment Inspection Interval Containment Inspection Program document. The document states "The welded attachments to the metallic liner (e.g., floor beams, seismic restraints, leak channels, equipment/pipe supports, etc.) do not perform a pressure retaining function associated with the containment support load path. For this reason, the welded attachments are classified as nonstructural and are not subject to inspection."

STAFF EVALUATION
The staff finds the applicant's response acceptable because the staff verified that there are no ASME Code Class MC supports that are subject to the applicant's ASME Code Section XI IWL program and that any the welded attachments to the metallic liner are classified as nonstructural and are not subject to inspection. This question is resolved.

Question No. B.2.28-SA-02

REQUEST
Justify use of ASME OM Code and ASME OM Code Case OMN-13 for Snubbers and attachments.

RESPONSE
The discussion of the ASME OM Code and ASME OM Code Case OMN-13 will be removed from the LRA Appendix B.2.28 ASME Section XI, Subsection IWF Program, "Program Description" and "Scope of Program" because ASME OM Code and ASME OM Code Case OMN-13 applies only to snubbers, and snubbers are not in the scope of License Renewal. The discussion of the ASME OM Code and ASME OM Code Case OMN-13 will be removed from the LRA Appendix A.1.1.2.8 ASME Section XI, Subsection IWF Program Description for the same reason. The component and piping supports (including any snubber attachments) will meet the requirements of ASME Section XI, Subsection IWF, 1989 Edition, and in accordance with ASME Code Case N-491-2.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has agreed to amend the LRA to delete the ASME OM Code and ASME OM Code OMN-13 references from the the scope of its ASME Section XI, Subsection IWF Program since the snubbers are not in the scope of license renewal. This question is resolved.

Question No. B.2.29-CM-01

REQUEST
GALL Report Section XI.S4 for the Appendix J Program describes that corrective actions are required for unacceptable performance. 1) Provide a comparison between the enhancement identified in LRA B.2.29 for corrective actions and the existing method of performing corrective actions. 2) Provide a list of Appendix J test failures due to causes other than valve seat leakage. Include the corrective actions taken to mitigate the failed components and restore Containment Integrity.

RESPONSE
Nuclear Condition Reports (NCRs) are required to be initiated by all employees according to the Corporate Corrective Action Program for unacceptable conditions such as a deficiencies or deviations in an item or activity that has affected or reasonably could affect nuclear safety or quality. NCRs are initiated when leakage rates do not meet the acceptance criteria and require investigation and appropriate corrective actions. However, an enhancement is needed to improve the site administrative procedures to describe the evaluation and corrective actions to be taken when leakage rates do not meet their specified acceptance criteria.

A record of the Appendix J test failures for Appendix J Type B and C testing is maintained by the Appendix J Program Engineer and is available for review at HNP. A review of failed tests through year 2000 (through RFO-9) was performed. Only two test failures due to causes other than valve seat leakage were identified, both on Type C testing. These were both related to flange leakage. NCRs were appropriately initiated. A leaking flange was identified in 2000 during the Local Leak Rate Test (LLRT) which was above the acceptance criteria. A Maintenance Work Request was initiated and the inboard valve flange was determined to be leaking. The inboard valve was disassembled from the penetration, the seating surfaces were cleaned, and the inboard O-ring and the outboard gasket were replaced. Another LLRT test was then performed with satisfactory results. A leaking flange was identified in 2004 during a LLRT which was above the acceptance criteria. A Maintenance Work Request was initiated and the gasket material on the inside face of blind flange was replaced. Another LLRT test was then performed with satisfactory results.

Additionally, a review of the failures due to valve seat leakage was performed through year 2000 and all had NCRs appropriately initiated.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it explains that the Appendix J testing program revealed no penetration leakage due to weld or material defects and because the applicant has clarified that its enhancement of the program was necessary to improve the quality and provide specific corrective action initiation criteria for its administrative procedures on the HNP 10 CFR Part 50, Appendix J program. This question is resolved.

Question No. B.2.29-CM-02

REQUEST
Program Element 1 describes the scope of the 10 CFR 50 Appendix J program.

Calculation No. HNP-P/LR-0615 describes that AMP B.2.29 is consistent with the GALL Report. It was noted however that the calculation states that Containment Structural Integrity, which requires a visual inspection of the structure surfaces prior to the Type A Containment leak rate test (ILRT) to verify no apparent changes in appearance or other abnormal degradation, using structural inspection attributes for Containment as shown in EGR-NGGC-0351 (Reference 5.28).

There is no mention of Surface Inspection in the GALL Report. Explain how this is consistent with the GALL Report, and whether the IWE Program credits B.2.29.

RESPONSE
The 10 CFR 50 Appendix J Aging Management Program (B.2.29) will be consistent with the GALL Report following enhancement. The requirement to perform a visual examination of the exposed accessible interior and exterior surfaces of the Containment, including the liner plate during the shutdown for each Type A containment leakage rate test is included based on Technical Specification surveillance requirement 4.6.1.6.1. This inspection is plant-specific and is above the requirements identified in the GALL Report's Appendix J Program. HNP considered performing plant-specific requirements over and above the requirements of the GALL Report as still consistent with the GALL Report.

The IWE Program does not credit Appendix J Program. In fact, the IWE Program basis document states that the Appendix J leak rate testing is evaluated as a separate AMP for License Renewal.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it explains that the Appendix J testing program includes a visual surface examination which is beyond the scope of the Appendix J program. The requirements for the visual inspection is an HNP Technical Specification requirement. The staff considers this to be an enhancement of the program beyond the recommended program element criteria in GALL AMP XI.S4, "10 CFR Part 50, Appendix J." This question is resolved.

B.2.30-JW-01

REQUEST
Have any masonry walls been added to the program due to license renewal?

RESPONSE
Masonry Walls in two structures were added to the Masonry Wall Program as a result of License Renewal. The two structures are the Security Building and the HVAC Equipment Room.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has identified the masonry wall locations that were added to the Masonry Wall Program as a result of the applicant's license renewal scoping, screening, and AMR methodologies. This question is resolved.

Question No. B.2.30-JW-02

REQUEST
Explain how often masonry walls are inspected for cracking. Explain if the inspection frequency varies from wall to wall. If the frequency does vary, explain the basis for the differences in frequency.

RESPONSE
The inspection interval for inspection of masonry walls for cracking varies from structure to structure but shall not exceed ten (10) years as established in a corporate level inspection procedure used for HNP, Robinson Nuclear Plant, Brunswick Nuclear Plant and Crystal River 3 Nuclear Plant. The basis for various frequencies at HNP was established based on the safety significance of the structure (based on Probabilistic Safety Analysis rated systems, structures, and components), the condition of the wall based on the results from previous structural inspections, and to accommodate work load management of the HNP engineering personnel. This results in a frequency of inspection which ensures there is no loss of intended function between inspections as described in GALL AMP XI.S5. For example, the masonry walls in the Reactor Containment Building are examined at 5 year intervals, the Fuel Handling Building at 7 year intervals, the Turbine Building at 8 year intervals, and several non-safety related structures at 9 year intervals, etc. An inspection frequency has not typically been established from wall to wall within a specific structure, however the Responsible Engineer has the responsibility to establish the inspection frequency based on the previous inspections. Since 1996, when the inspections were initiated, there have not been any unacceptable conditions identified on masonry walls from cracking. Therefore, there has not been a need to change the inspection interval for masonry walls. If unacceptable conditions are identified in the future, initiation of a Nuclear Condition Report and corrective actions are required. This corrective action could result in increasing the inspection interval for a specific masonry wall, based on the Responsible Engineer's disposition. The same corporate procedure is used for inspecting building concrete/grout. A recent example involved increasing the inspection interval for a foundation in the Diesel Generator to a yearly frequency based on the condition of the grout. It should also be noted that there are no unreinforced masonry walls located in safety related areas at HNP.

HNP does not consider the methodology for selecting the interval for inspection of masonry walls an exception to GALL AMP XI.S5 Program Attribute 4 based on the following: IE Bulletin (IEB) 80-11 was issued to HNP for information while HNP was under construction. HNP designed and constructed Category I masonry walls as described in the HNP FSAR (Section 3.8.4.8). In order to preclude problems of the type addressed by IEB 80-11, HNP designed all masonry walls in the proximity of safety-related equipment to meet seismic design criteria. The walls were inspected by QA/QC inspectors in accordance with implementation procedures. In addition , attachments of equipment to masonry block walls was approved on a case by case basis. Safety related masonry walls at HNP are analyzed in a structural calculation. Several NRC IE Construction Assessment Teams examined HNP's costruction activities of masonry walls in 1984 and 1986 and validated IEB 80-11 requirements were met. The following NRC Letters document that HNP designed and constructed masonry walls to IEB 80-11 requirements: NRC IR 50-400/84-41, 50-400/84-48, 50-400/86-03, 50-400/86-06 and 50-400/87/32.

The masonry walls at HNP were constructed to the requirements of IEB 80-11 and without the design and construction problems typical of earlier plants. The HNP masonry walls at HNP have proven to be designed, constructed, and verified to QA requirements and no unacceptable conditions have been identified in over twenty (20) years after installation. HNP considers the methodology utilized by the Responsible Engineer for selecting the inspection intervals for masonry walls at HNP to meet the GALL AMP XI.S5 Program Attribute 4 attributes. In conclusion, at HNP there is no need to inspect non-reinforced masonry walls more frequent than reinforced masonry walls, unless unacceptable conditions are identified.

STAFF EVALUATION

The staff finds the applicant's response acceptable because (1) the applicant has explained how often masonry walls are inspected for cracking, and (2) the applicant has explained the logic and basis for the inspection frequency not varying from wall to wall, but varying only structure to structure. This question is resolved.

Question No. B.2.31-JW-01

REQUEST
For concrete structures below grade, 1) provide the dates and results (at specific locations, not average or ranges) of the two most recent tests and the scheduled frequency of groundwater monitoring. 2) Clarify if the Structures Monitoring Program will continue to perform the groundwater monitoring and inspect all inaccessible areas that may be exposed by excavation, whether the environment is considered aggressive or not.

RESPONSE
As stated in LRA Section 3.5.2.2.1, site groundwater was sampled for License Renewal in August 2005 from two wells (Well 57 – pH 7.6, chlorides 290 mg/l, sulfate 2.4 mg/l; Well 59 - pH 7.9, chlorides 42 mg/l, sulfate 2.1 mg/l). Prior to this, groundwater was sampled in 1973 from three site wells as recorded in FSAR Table 2.4.13-8 (Well 2 - pH 7.3, chlorides 23 mg/l, no sulfate reading; Well 4A - pH 7.9, chlorides 22 mg/l, no sulfate reading; Well 7A - pH 7.9, chlorides 21 mg/l, no sulfate reading). The original 1973 wells are no longer active. The Structures Monitoring Program will add a groundwater implementing procedure to require periodic groundwater chemistry monitoring including consideration for potential seasonal variations (as stated in LRA Appendix B Section B.2.31). The monitoring will begin on five (5) year intervals from 2005 until the extended period of operation (for trending prior to the extended operation period) and then on a yearly interval thereafter. This enhancement is being implemented even though the groundwater is currently non-aggressive. In addition, a Structures Monitoring Program implementing procedure is being enhanced to require inspection of inaccessible below-grade concrete when exposed by excavation prior to backfilling. The enhancement for inspecting inaccessible below-grade concrete when exposed by excavation will also be continued during the period of extended operation even though the groundwater is non-aggressive.

STAFF EVALUATION
The staff finds the applicant's response acceptable because (1) the applicant has provided the dates and results of the two most recent groundwater monitoring tests and discussed the scheduled frequency of groundwater monitoring, and (2) the applicant has explained that the Structures Monitoring Program will continue to perform groundwater monitoring and inspect inaccessible areas when exposed by excavation even if the groundwater is non-aggressive. This question is resolved.

Question No. B.2.31-JW-02

REQUEST
Explain how the frequency of inspection for the structures, buildings and components within the scope of this program are affected when aging effects are discovered.

RESPONSE
The administrative procedure for the Structures Monitoring Program requires a reassessment and documented justification for an appropriate periodic inspection interval for each License Renewal structural system (structure) based on the results of the inspection. The administrative procedure for the Structures Monitoring Program also states the inspection interval shall be commensurate with the safety significance of the structure and its condition but shall not exceed ten (10) years. Based on this, the inspection intervals for License Renewal structures varies from structure to structure. For example, the Reactor Containment Building internal concrete is examined at 5 year intervals, the Fuel Handling Building at 7 year intervals, the Turbine Building at 8 year intervals, and several non-safety related structures at 9 year intervals.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has stated that the administrative procedure for the Structures Monitoring Program requires a reassessment and documented justification for an appropriate periodic inspection interval for each license renewal structure based on inspection results. This question is resolved.

Question No. B.2.31-JW-03

REQUEST
Has HNP ever discovered ground water infiltration through underground exterior walls of buildings within the Structures Monitoring Program? If yes provide the documentation for these issues showing when, where and how they were discovered. Also, how these issues were evaluated and resolved with a discussion on the need for any follow up inspections.

RESPONSE
The Structures Monitoring Program inspects the building structures for groundwater or other water seepage as one of the inspection attributes. During the baseline inspections (per the Maintenance Rule) of the structures in 1996, groundwater intrusion and/or seepage was recorded on a number of structures. The structures with groundwater intrusion and/or seepage included the Reactor Auxiliary Building, the Fuel Handling Building, and the Waste Processing Building. The groundwater intrusion and/or seepage was evaluated as acceptable by HNP Engineering and a comment was added that monitoring should be continued. However, at one location, the Reactor Auxiliary Building was recorded as unacceptable due to water seepage into the 216' elevation pipe tunnel and from water seepage from seismic gaps and penetrations. This was addressed with a plant modification. Other actions taken to remove/direct water in-leakage included the establishment of additional measures; such as caulking concrete cracks, using tygon tubing for drainage, and cutting channels into concrete floors, to direct water in-leakage towards floor drains. During the structure inspections in 2006, groundwater intrusion and/or seepage was recorded again on a number of structures, including the Reactor Auxiliary Building, the Fuel Handling Building, the Waste Processing Building, and the Turbine Building. However, all of the locations were recorded as acceptable by HNP Engineering and a comment was added that monitoring should be continued. The groundwater intrusion and/or seepage in some of the lower elevations is nearly continuous but is minimal and is adequately removed with the floor drains system. HNP does consider the minimal intrusion and/or seepage an internal flooding concern. In general, after identifying the specific groundwater intrusion and/or seepage, the groundwater intrusion and/or seepage is identified to the Maintenance organization as a housekeeping condition through the work management process. The specific areas are cleaned up and groundwater may be redirected as appropriate. Corrosion to any support steel in the areas due to the groundwater intrusion is removed and recoated as identified through system and structure walkdowns. If the groundwater intrusion and/or seepage is recorded as unacceptable by HNP Engineering, then the condition is entered into the corrective action program for resolution. There are currently no long term plans identified from Structures Monitoring Program inspections to eliminate the groundwater intrusion and/or seepage. However, HNP Engineering will continue to monitor the groundwater intrusion and/or seepage as part of the Structures Monitoring Program and has decreased the inspection intervals for the affected structures from ten (10) years [Reactor Auxiliary Building (6 years), Fuel Handling Building (7 years), Turbine and Waste Processing Building (8 years)]. HNP Maintenance will continue to maintain the water control measures installed to route water in-leakage towards plant floor drains.

Historically, groundwater intrusion into the Reactor Auxiliary Building lower elevations was identified as early as 1980. Pressure grouting in 1984, and sealant injection, and other water control techniques since then have been utilized to help control the groundwater intrusion but some groundwater intrusion is still ongoing as identified by the structure inspection reports in 1996 and 2006.

Inspection reports are available for review at HNP.

STAFF EVALUATION

The staff finds the applicant's response acceptable because (1) the applicant stated that ground water infiltration has occurred through underground exterior walls of buildings within the Structures Monitoring Program, and (2) the applicant explained when, where and how the ground water infiltration occurred and how the issues were evaluated and resolved, or currently being monitored. This question is resolved.

Question No. B.2.32-JW-01

REQUEST
Prior to the period of extended operation one enhancement to the B.2.32 Program is to revise the administrative controls that implement the program to require initiation of a Nuclear Condition Report (NCR) for degraded plant conditions and require, as a minimum, the initiation of an NCR for any condition that constitutes an "unacceptable" condition based on the acceptance criteria specified. Since NCRs are not currently used, explain how unacceptable conditions are now documented under the program and processed for engineering evaluation or corrective action.

RESPONSE
Non Conformance Reports (NCRs) are required to be initiated by all employees according to the Corporate Corrective Action Program for unacceptable conditions such as a deficiencies or deviations in an item or activity that has affected or reasonably could affect nuclear safety or quality. The enhancement to the administrative procedure for the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants Program improves the administrative procedure by clarifying the corporate requirement. This enhancement also makes this administrative procedure consistent with the corporate level procedure used for the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants Program.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has stated that non conformance reports (NCRs) are required to be initiated by all employees according to the Corporate Corrective Action Program already. The enhancement is only to the administrative procedure for the RG 1.127, Inspection of Water-Control Structures Associated With Nuclear Power Plants Program to improve the administrative procedure by clarifying the corporate requirement. This question is resolved.

Question No. B.2.33-RM-01

REQUEST
In LRA, Appendix B, Sections B.2.33, B.2.34, B.2.35, B.2.36, and B.2.37, the applicant states that these programs are new with no site-specific operating experience history. The SRP-LR, Revision 1, Appendix A, Branch Technical Position RLSB-1 states that an applicant may have to commit to providing operating experience in the future for new program to confirm their effectiveness. Describe how operating experience will be captured to confirm the program effectiveness and the process to be used to adjust the program as needed.

RESPONSE
Plant-specific and industry wide operating experience (OE) was considered in the development of the Appendix B electrical programs. Industry operating experience that forms the basis for these Appendix B electrical programs is included in the operating experience element of the corresponding NUREG-1801 Chapter XI Programs. Plant-specific operating experience was reviewed to ensure that the NUREG-1801 Chapter XI Programs will be effective aging management programs for the period of extended operation (PEO). This review is discussed in a plant evaluation. This review confirms that the operating experience discussed in the NUREG-1801 Chapter XI Programs is bounding. Operating experience going forward will be captured through the HNP Corrective Action and Operating Experience Programs implemented in accordance with Progress Energy corporate procedures. This ongoing review of operating experience will continue throughout the PEO and the results will be maintained on site. The administrative controls that implement the Corrective Action and Operating Experience Programs are implemented in accordance with the HNP QA Program, which is in conformance with 10 CFR 50, Appendix B. This process will verify that the Appendix B electrical programs continue to be effective in the management of aging effects.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant evaluated the plant-specific and industry operating experience during the development of the Appendix B electrical programs as discussed in their plant evaluation. In addition, the applicant confirmed that the operating experience discussed in the NUREG-1801 Chapter XI Programs is bounding and the operating experience going forward will be captured through the HNP Corrective Action and Operating Experience Programs implemented in accordance with Progress Energy corporate procedures. This question is resolved.

Question No. B.2.33-RM-02

REQUEST
In LRA AMP Section B.2.33, the applicant states that the technical basis for selecting the sample of cables and connections to be inspected is defined in the implementing HNP program document. The staff requests the applicant to discuss the following: (1) Explain the sample selection method used for cables and connections from accessible areas such that they are inspected and represent, with reasonable assurance, all cables and connections, and (2) If an unacceptable condition or situation is identified for a cable or connection in the inspection sample, explain the inspection sample expansion and corrective actions.

RESPONSE
(1) The sample selection method used in the implementing HNP program document follows the guidance of NUREG-1801, Section XI.E1, whereby a representative sample of accessible electrical cables and connections installed in adverse localized environments are visually inspected and represent, with reasonable assurance, all cables and connections in that area. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service condition for the electrical cable or connection. The HNP program utilizes plant operating experience (OE) to determine the plant areas to be inspected. HNP OE is used to identify past cable failures, cables that exhibited the effects of aging, hot spots, and adverse localized environments. Part of this OE review includes conversations with maintenance personnel and the use of environmental surveys. Based on this review of OE, the plant areas to be inspected become localized in nature, consisting of a limited area (or subset) of a much larger plant area or zone. The sample selection of cables and connections inspected within the limited plant area bound all cables and connections in the area since the inspection focuses on the worst case environments.

(2) Corrective actions will be implemented through the HNP Corrective Action Program and may include, but are not limited to, testing, shielding or otherwise changing the environment, or relocation or replacement of the affected cable or connection. When an unacceptable condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible insulated cables and connections. The Corrective Action Program is implemented by the HNP QA Program in accordance with 10 CFR 50, Appendix B.

STAFF EVALUATION
The staff finds the applicant's response acceptable because (1) the applicant has explained that it utilizes OE programs to determine the plant areas to be inspected and the sample selection method used for cables and connections from accessible areas such that they are inspected and represent, with reasonable assurance, all cables and connections consistent with the guidance provided in GALL AMP XI.E1, and (2) the applicant has clarified that when an unacceptable condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible insulated cables and connections through its corrective action program. The applicant stated that it will amend the LRA Appendix B to clarify the OE review. This question is resolved.

Question No. B.2.34-RM-01

REQUEST
In LRA, Appendix B, Section B.2.34, the applicant describes the AMP for Non-EQ Instrumentation Circuits Program. Clarify whether the tests proposed in the program include both cables and connections. If not, address how the cables and connections are tested.

RESPONSE
The tests proposed in the program include both cables and connections used in radiation monitoring and nuclear instrumentation circuits. The term "cable systems" used in the LRA refers to the combination of cables and connections.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that the program include both cables and connections used in radiation monitoring and nuclear instrumentation circuits. This question is resolved.

Question No. B.2.34-RM-02

REQUEST
In LRA, Appendix B, Section B.2.34, the applicant states that for radiation monitoring circuits and the RG 1.97 wide range neutron flux monitoring circuits, the review of calibration results or findings of surveillance testing will be used to identify the potential existence of cable system aging degradation. Clarify if radiation monitoring and wide range neutron monitoring cable systems are disconnected during calibration or surveillance testing.

RESPONSE
The radiation monitoring cable systems are initially disconnected at the channel drawers for calibration of individual circuit electronics. Loop calibration or surveillance testing is performed utilizing a check source with the cable systems connected. For radiation monitoring circuits, the review of calibration results or findings of surveillance testing will be used to identify the potential existence of cable system aging degradation.

The RG 1.97 wide range neutron flux monitoring cable systems are also disconnected at the channel drawers for calibration of individual circuit electronics but are not equipped with a check source. Therefore, the cable systems used in the RG 1.97 wide range neutron flux monitoring circuits require testing to identify the potential existence of cable system aging degradation. The RG 1.97 wide range neutron flux monitoring circuits are part of the Excore Nuclear Instrumentation System. Similar to the cable systems used in the excore source, intermediate, and power range nuclear instrumentation circuits, the RG 1.97 wide range neutron flux monitoring circuits will be tested at a frequency not to exceed 10 years based on engineering evaluation, with the first testing to be completed before the end of the current license term.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant clarified that the wide range neutron monitoring cable systems are disconnected during calibration and the wide range neutron flux monitoring circuits will be tested at a frequency not to exceed 10 years based on engineering evaluation, with the first testing to be completed before the end of the current license term. The applicant stated that it will amend the LRA. This question is resolved.

Question No. B.2.34-RM-03

REQUEST
In LRA Section B.2.34, the applicant states that exposure of electrical cables to adverse localized environments caused by heat or radiation can result in reduced insulation resistance. Why is moisture not specified as a cause for reduced insulation resistance as specified in GALL AMP XI.E2? Also, clarify whether all instrumentation circuits susceptible to moisture sensitive to signal inaccuracies are included in the EQ program.

RESPONSE
Moisture is specified as a cause for reduced insulation resistance as shown in LRA Table 3.6.2-1 (page 3.6-19). LRA Section B.2.34 is meant to provide summary level program information and not intended to exclude moisture. Note that the conclusion for LRA Section B.2.34 (page B-94) includes moisture as well as heat and radiation. Also, moisture is included as a stressor under the environments shown in LRA subsection 3.6.2.1.1 (page 3.6-4).

Not all instrumentation circuits susceptible to moisture, sensitive to signal inaccuracies are included in the HNP EQ Program. To discover that population of circuits not included in the HNP EQ Program, all impedance sensitive circuits within the scope of License Renewal that may experience a reduction in insulation resistance (IR) due to heat, radiation or moisture were screened against the criteria given in NUREG-1801, Section XI.E2. The resultant list of impedance sensitive neutron and radiation monitoring signal cables that may experience a reduction in IR are included in LRA, Appendix B, Section B

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that it had considered moisture as a stressor under the environments for this program as shown in LRA subsection 3.6.2.1.1. The applicant has also clarified that not all instrumentation circuits susceptible to moisture, sensitive to signal inaccuracies are included in the HNP EQ Program. This question is resolved.

Question No. B.2.35-RM-01

REQUEST
Are all medium voltage cables within the scope of license renewal included in HNP AMP B.2.35 (GALL AMP XI.E3). If not, provide a listing of the Medium Voltage cables installed at HNP and show how they were screened out for this program.

RESPONSE
No. Medium voltage cables within the scope of License Renewal that did not meet the criteria specified in NUREG 1801 Section XI.E3 are not included in HNP AMP B.2.35. All medium voltage cables within the scope of License Renewal were screened against the criteria given in NUREG 1801 Section XI.E3. Consistent with NUREG-1801, Section XI.E3, medium voltage cables included in HNP AMP B.2.35 meet the following criteria: (1) they are located underground and assumed wet, and (2) they must be energized at least 25% of the time. HNP medium voltage cables within the scope of License Renewal that did not meet these criteria were screened out and are not included in HNP AMP B.2.35.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that not all medium voltage cables within the scope of License Renewal are included in this program and the cables that did not meet the criteria specified in NUREG 1801 Section XI.E3 were screened out of this program. During the audit and review, the applicant has provided a listing of all medium voltage cables and the basis for not including those cables in HNP AMP B.2.35. This question is resolved.

Question No. B.2.37-XI.E6-RM-01

REQUEST
GALL AMP XI.E6 states that if an unacceptable condition or situation is identified in the selected sample, a determination is made as to whether the same condition or situation is applicable to other connections not tested. Please clarify whether this recommendation will be implemented for HNP LRA Section B.2.37. If not, explain why this recommendation is not applicable to HNP.

RESPONSE
As stated in HNP LRA Section B.2.37, the HNP Connections Program is consistent with GALL AMP XI.E6. As specified in the program basis document, if an unacceptable condition or situation is identified in the selected sample, a determination will be made as to whether the same condition or situation is applicable to other connections not tested.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that if an unacceptable condition or situation is identified in the selected sample, a determination will be made as to whether the same condition or situation is applicable to other connections not tested as recommended in GALL AMP XI.E6. This question is resolved.

Question No. B.2.37-XI.E6-RM-02

REQUEST
In calculation No. HNP-P/LR-0668 (AMP XI.E6 evaluation), the applicant states that the program elements “Scope of Program,” and “Detection of Aging Effects,” program elements are not consistent with GALL AMP XI.E6 program elements “Scope of Program,” and “Detection of Aging Effects.” However, LRA Section B.2.37 states that all elements of this program are consistent with GALL AMP XI.E6. Please identify these exceptions in LRA Section B.2.37 and its technical justifications.

RESPONSE
This program was revised after the original submittal of the HNP LRA in 2006. The basis for this revision was the NRC Letter dated March 16, 2007, "Staff Response to the Nuclear Energy Institute (NEI) White Paper on Generic Aging Lessons Learned (GALL) Report Aging Management Program (AMP) XI.E6, 'Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirement'". The exceptions to LRA Section B.2.37 are described below. Under program element "Scope of Program" GALL AMP XI.E6 states "Connections associated with cables in scope of license renewal are part of this program, regardless of their association with active or passive components." Consistent with the clarification provided in the NRC letter, this element of calculation No. HNP-P/LR-0668 was revised to read "The HNP AMP applies to cable connections within the scope of license renewal not covered under the existing EQ program. The scope of this program includes only external cable connections terminating at an active device such as motor, motor control center, switchgear or of a passive device such as a fuse cabinet. Wiring connections internal to an active assembly installed by manufacturers are considered a part of the active assembly and therefore are not within the scope of this program." Under program element “Detection of Aging Effects” GALL AMP XI.E6 states “"Electrical connections within the scope of license renewal will be tested at least once every 10 years. Testing may include thermography, contact resistance testing, or other appropriate testing methods. This is an adequate period to preclude failures of the electrical connections since experience has shown that aging degradation is a slow process. A 10-year testing interval will provide two data points during a 20-year period, which can be used to characterize the degradation rate. The first tests for license renewal are to be completed before the period of extended operation." Consistent with the test frequency flexibility provided in the NRC letter, this program element was revised to read "This program will be implemented as a one-time inspection on a representative sample of non-EQ cable connections within the scope of license renewal prior to the period of extended operation. Inspection methods may include thermography, contact resistance testing, bridge balance testing, or other appropriate testing methods. This one-time inspection verifies that the 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.

GALL AMP XI.E6 along with the clarification provided in the NRC letter forms the technical basis and justification for the HNP Program described in LRA Section B.2.37. These exceptions to GALL AMP XI.E6 will be noted in an amendment to LRA Section B.2.37.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that it will amend the LRA to identify the exceptions to the program elements “Scope of Program,” and “Detection of Aging Effects.” The proposed exceptions are acceptable because they are consistent with the staff position described in NRC Letter dated March 16, 2007. This question is resolved.

Attachment 1 - Question and Answer Database For AMR and AMP Reviews
Audit and Review Related to the License Renewal Application for
Harris Nuclear Power Plant

Question No. B.3.2-RM-01

REQUEST
In LRA, Appendix B, Section 3.2, the applicant states that the HNP EQ program has been effective at managing aging effects and the overall effectiveness of the program is demonstrated by the excellent operating experience for the systems and components in the program. Discuss the details of operating experience that led to this conclusion. Show where an existing program has succeeded and where it has failed in identifying aging degradation in a timely manner with the present program.

RESPONSE
The HNP EQ Program is continuously monitoring the qualification basis for all equipment in the EQ Program, including aging effects and their impact on the qualified lives of EQ equipment. Specific examples of activities that have taken place based on these monitoring activities are provided below:

Plant Change Request (PCR) 5809 (completed in March of 1991) was developed in order to evaluate the EQ impact of containment temperature data that had been obtained from temporary modification PCR 3315. PCR 3315 installed 11 RTD's to determine the actual temperatures in Containment. The results of PCR 5809 included the re-calculation of the qualified lives of 12 EQ documentation package (EQDPs) in order to assure that qualified lives of components were met.

PCR 6406 (completed in March of 1994) evaluated the Main Steam Tunnel (MST) qualified life calculations based on an evaluation of outdoor temperatures. This increase in outdoor temperature ultimately resulted in a Technical Specification/FSAR change to increase the MST ambient temperature. The PCR revised all EQ documentation impacted by the Technical Specification/FSAR change.

The information regarding PCR 5809 and PCR 6406 are examples of actions taken under the EQ Program to assure that environmental qualification of components was maintained.

NCR 133798 (completed in August 2004) was written because a slow stroke time on a Service Water solenoid operated valve (SOV) indicated a problem with the valve's solenoid. An incorrect assumption on the energization time of the solenoid led to the initiation of Engineering Change (EC) 59305. This EC changed the EQ documentation package for two SOVs to reflect the accurate service life energization time of these EQ components. NCR 133798 is an example of the EQ Program reacting to operating experience data to assure the continued environmental qualification of equipment.

The HNP EQ Program is required to be assessed by knowledgeable personnel from outside of the site EQ group at an interval of no more than 4 calendar years. Self Assessment (SA) 80126 (conducted in August 2003) was the latest formal assessment of the EQ program. Although this SA discovered a variety of improvement opportunities, there were no issues or findings which impact program effectiveness. This SA is an example of continuous self improvement.

The HNP EQ Program System Health Report is a web based document used to indicate the overall heath of the EQ Program and to proactively identify declining trends in the program.

STAFF EVALUATION

The staff finds the applicant's response acceptable because the applicant has provided examples of EQ program operating experiences to demonstrate its program effectiveness and the opportunities for program improvements. This question is resolved.

Question No. B.3.2-RM-02

REQUEST
GALL AMP X.E1 states that important attributes of a reanalysis include analytical methods, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions (if acceptance criteria are not met). Explain why these attributes are not discussed in HNP LRA Section B.3.2 as recommended in GALL AMP X.E1.

RESPONSE
These attributes are is discussed in Subsections 4.4.1 and 4.4.2 of the HNP LRA.

HNP LRA Section B.3.2 will include a statement that refers to LRA Section 4.4 for a discussion of EQ Program reanalysis attributes.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has provided a discussion of important attributes of EQ program reanalysis in LRA TLAA Sections 4.4.1 and 4.4.2as recommended in GALL AMP X.E1. In addition, the applicant will revise LRA Section B.3.2 that will include a statement that refers to LRA Section 4.4 for a discussion of EQ Program reanalysis attributes. This question is resolved.

Question No. B.3.2-X.E1-RM-02

REQUEST
In calculation No. HNP-P/LR-0650 (AMP X.E1 evaluation), the applicant states that the HNP EQ program conforms to Regulatory Guide 1.89, Rev.0, not Rev. 1. However, GALL AMP X.E1 recommends Regulatory Guide 1.89, Rev.1, as the regulatory guidance for complying with 10 CFR 50.49. Explain why LRA Section B 3.2 program elements “Parameters Monitored/Inspected,” and “Scope of Program,” program elements did not identify this exception. Provide technical justification for this exception.

RESPONSE
The HNP EQ programs licensing basis is Regulatory Guide 1.89, Rev. 0. This is an exception to GALL AMP X.E1 which references Regulatory Guide 1.89, Rev. 1. The original licensing basis of the HNP EQ Program is not Regulatory Guide (RG) 1.89, Rev. 1, as specified in NUREG-1801, Section X.E1. HNP was originally licensed as a NUREG-0588, Category II plant, and IEEE Std 323-1971 was the original EQ Program basis. RG 1.89, Rev. 1 had not been issued when the HNP construction permit SER was issued. RG 1.89, Rev. 1 describes a method acceptable to the NRC staff for complying with § 50.49 of 10 CFR Part 50. The acceptable method follows the procedures described by IEEE Std 323-1974. Currently, the HNP EQ Program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety. Under 10 CFR §54.21(c)(1)(iii), the HNP EQ Program, which implements the requirements of 10 CFR 50.49, is viewed as an aging management program for License Renewal. Section 4.4.2.1.3 of the “Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants” (SRP-LR) states that the staff evaluated the EQ program (10 CFR 50.49) and determined that it is an acceptable aging management program to address environmental qualification according to 10 CFR 54.21(c)(1)(iii).

This exception will be identified in an amendment to the LRA.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant stated that it will amend the LRA to identify the exceptions to the program elements “Parameters Monitored/Inspected,” and “Scope of Program.” (conforms to Regulatory Guide 1.89, Rev.0, not Rev. 1 as specified in the GALL AMP X.E1). In addition, the staff finds these exceptions acceptable because the HNP EQ program meets the requirements of 10 CFR 50.49 for the applicable electrical components important to safety and is consistent with the applicant's current licensing basis. This question is resolved.

Question No. GALL XI-RM-01

REQUEST
Please identify all non-safety electrical/I&C containment penetration assemblies at HNP? Identify the aging effects and explain how these penetration assemblies are managed.

RESPONSE
All electrical/I&C containment penetration assemblies at HNP are in the EQ Program. Their EQ documentation package (EQDP) is considered a TLAA.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that all containment electrical penetrations are environmentally qualified and they are included in the EQ program. This question is resolved.

Question No. 3.1-FS-01

REQUEST
GALL AMP XI.M12 is not applicable to HNP. What are the HNP's CASS components' casting method, molybdenum content, and ferrite content?

RESPONSE
A methodology for screening cast austenitic stainless steel (CASS) components for susceptibility to thermal aging embrittlement was provided in the NRC staff's evaluation and proposed resolution to License Renewal Issue No. 98-0030. The evaluation and proposed resolution was provided in a letter from C.I. Grimes (USNRC) to D. Walters (NEI), License Renewal Issue No. 98-0030, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Components, May 19, 2000. The letter is referenced in NEI 95-10, Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule (Hereinafter referred to as the "Grimes Letter"). Revision 6 of NEI 95-10 was endorsed by Revision 1 to Regulatory Guide 1.188, Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses.

Determination of the susceptibility of CASS components to thermal aging can use a screening method based upon the molybdenum (Mo) content, casting method, and ferrite content. The specific screening criteria acceptable to the staff are outlined in Table 2 of the Grimes Letter, and are applicable to all primary pressure boundary and reactor vessel internal (RVI) components constructed from SA-351 Grade CF3, CF3A, CF8, CF8A, CF3M, CF3MA, or CF8M, with service conditions above 250°C (482°F).

The significance of finding a particular component not susceptible or potentially susceptible is described in the Grimes Letter for each component type. The examination requirements for each component type are provided in Table 3 of the Grimes Letter.

Per Table 3 of the Grimes Letter, valve bodies and pump casings do not require a susceptibility evaluation because both susceptible and non-susceptible components are examined to ASME Section XI requirements. As shown on page 3.1-62 of the LRA, CASS components of the Reactor Vessel Internals are managed by the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program (B.2.6) for Loss of Fracture Toughness due to Thermal Embrittlement. The remaining population of CASS components that require a susceptibility review included the Reactor Coolant Loop elbows and the Pressurizer Spray Head. The d-ferrite level for the Reactor Coolant Loop elbows was calculated as part of the leak-before-break evaluation performed in WCAP-14549-P, Addendum 1, Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Harris Nuclear Plant for the License Renewal Program. The reactor coolant loop elbows are low-molybdenum statically cast components. Since the maximum calculated d-ferrite level is $\leq$ 20%, the elbows are not susceptible to thermal aging. For the Pressurizer Spray Head, the Certified Material Test Report (CMTR) information was reviewed and the d-ferrite level calculated. The resultant d-ferrite level was below the screening threshold regardless of casting method. Therefore, the Pressurizer Spray Head is not susceptible to thermal aging.

Since the population of components reviewed for thermal aging were shown not to be susceptible to thermal aging, the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is not required for License Renewal.

Specific details on the material composition and casting methods are available in the basis document (HNP-P/LR-0657) where the preceding evaluation was

performed and is available for your review during the audit.

STAFF EVALUATION

The staff reviewed the specific details on the material composition and casting methods that were provided to the staff during the AMP audit and found the applicant's evaluation of the HNP CASS components for susceptibility to thermal aging to be acceptable based on the applicant's application of the NRC's CASS susceptibility criteria for thermal aging embrittlement, as given in the Chris Grimes' letter of May 19, 2000 (ADAMS ML003717179). Based on use of these criteria, the staff concluded that the applicant had a valid basis for screening out its CASS piping components at HNP from the need to manage thermal aging embrittlement and for not including a program for CASS piping materials that corresponds to GALL AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steels (CASS)." This question is resolved.

Question No. 3.1-FS-02

REQUEST
LRA Table 3.1.2-1, on Page 3.1-41 identifies water chemistry and one time Inspection (OTI) programs to mange cracking due to SCC for SS vessel flange leak detection line. GALL Report Table 3.1.1, item 23 recommends a plant-specific program which should be further evaluated by the staff. LRA Section 3.1.2.2.7 states that the OTI program provides an inspection that verifies either unacceptable degradation is not occurring or triggers actions. Please explain how OTI detects cracking due to SCC for this item. Please describe any site specific or industry operating experience with regard to failure of the SS vessel flange leak detection line that has been identified by HNP.

RESPONSE
Please describe any site specific or industry operating experience with regard to failure of the SS vessel flange leak detection line that has been identified by HNP.

HNP reviewed site and industry OE since January 1, 2005. No site specific or industry OE has been identified with regard to failure of the SS vessel flange leak detection line.

Please explain how OTI detects and monitors cracking due to SCC for this item.

Enhanced Visual (VT-1 or equivalent) and/or Volumetric (RT or UT).

Further, what are the acceptance criteria and corrective actions if cracks are identified by One-Time Inspection?

Corrective Actions

Unacceptable components/structures are processed according to the provisions of the corporate Corrective Action Program which complies with 10 CFR 50 Appendix B.

Why were the water chemistry and one time Inspection (OTI) programs chosen to manage cracking due to SCC for the vessel flange leak detection line?

The vessel flange leak detection line is not classified as ASME Code Class 1, therefore the leak detection line is not included in the One-Time Inspection of Small Bore Class 1 RCS Piping Program. Although these lines are typically dry, if any leaks were to occur at the vessel flange, the components would be exposed internally to primary water. Thus, the Water Chemistry Program is appropriate to manage cracking due to SCC. Since there has been no operating experience that identifies cracking in these lines, the One-Time Inspection program is appropriate to verify the aging effect has not occurred.

STAFF EVALUATION
The staff finds the applicant response to its question acceptable because the applicant provided bases for using water chemistry and OTI programs to manage cracking due to SCC for components that roll up to LRA Table 3.1.1-2.

Attachment 1 - Question and Answer Database For AMR and AMP Reviews
Audit and Review Related to the License Renewal Application for
Harris Nuclear Power Plant

Question No. 3.1-FS-05

REQUEST
LRA, Table 3.1.2-1, page 3.1-46 lists stainless steel CRDM head penetration thermal sleeves in treated water (outside) environment. Notes J and 113 are used for this line items. Note J indicates that neither the component nor the material and environment combination is evaluated in the GALL Report and Note 113 states that these aging effects do not affect the insulation intended function of the thermal sleeves. Therefore, the LRA identifies “None” for aging effect requiring management and aging management program. If a component does not have an intended function to be managed during the period of extended operation, then that component should be screened out and not included in the AMR tables. Please justify elimination of aging effect for stainless steel CRDM head penetration thermal sleeves in treated water in accordance with the requirements of 10 CFR 54.

RESPONSE
HNP will use a combination of the Water Chemistry Program and the One-Time Inspection Program to manage loss of material and cracking of this component.

The Water Chemistry Program provides for monitoring and controlling of water chemistry using site procedures and processes for the prevention or mitigation of the cracking and loss of material aging effects. The One-Time Inspection Program provides an inspection that either verifies that unacceptable degradation is not occurring or triggers additional actions that assure the intended function of affected components will be maintained during the period of extended operation.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds this response acceptable, since the applicant adequately revised the AMR line items in Table 3.1.2-1 to include loss of material and cracking of stainless steel CRDM head penetration thermal sleeves exposed to treated water and that the applicant appropriately added the Water Chemistry and One-Time Inspection programs for managing this aging effect.

Question No. 3.1-FS-06

REQUEST
GALL Report, Volume 2, Item IV.A2-16 (R81), lists inlet and outlet safety injection nozzles made of steel with stainless steel cladding. The GALL Report recommends a TLAA to be evaluated for this managing loss of fracture toughness due to neutron irradiation embrittlement in reactor coolant and neutron flux environment for this item. This line rolls up to the GALL Report, Volume 1, Table 1, Line 17. Please explain why comparable line item for inlet and outlet safety injection nozzles is not included in LRA Table 3.1.2-1.

RESPONSE
As stated in Section 4.2.1 (page 4.2-3) of the HNP LRA:

> The beltline, as defined by 10 CFR 50.61(a)(3), is the region of the reactor pressure vessel that directly surrounds the effective height of the active core and adjacent regions of the reactor pressure vessel that are predicted to experience sufficient neutron radiation damage to be considered in the selection for the most limiting material with regard to radiation damage. The threshold fluence for beltline material is 1×10^{17} n/cm^2, E > 1.0 MeV. The existing AREVA neutron fluence models have been extended to facilitate this evaluation. The materials outside of the traditional beltline region which are expected to receive fluence values greater than 1017 n/cm2 were evaluated, and none of these materials were determined to be limiting.

The HNP reactor vessel does not have safety injection nozzles.

The reactor vessel outlet nozzles were not identified as components expected to receive fluences greater than 1017 n/cm2 (E > 1.0 MeV). Therefore, the reactor vessel outlet nozzles do not apply to the GALL Report, Volume 2, Item IV.A2-16 (R81).

Four other reactor coolant pressure boundary components outside the beltline region are expected to receive fluences greater than 10^{17} n/cm^2 (E > 1.0 MeV). These components include (1) the circumferential weld that is between the upper and intermediate shells, (2) the upper shell, (3) the inlet nozzle welds, and (4) the inlet nozzle. These components were evaluated and none of these materials were determined to be limiting in ART, Cv_{USE} or RT_{PTS} values.

The LRA will be amended to include a discussion of the above components and AMR line item(s) will be added as appropriate.

A License Renewal Application amendment is required.

STAFF EVALUATION
For ferritic steel materials (i.e, carbon steel, low alloy steel, and cast irons), the staff uses a neutron fluence of 1×10^{17} n/cm^2 ($E \geq 1.0$ MeV) as it threshold for initiation of neutron irriadation embrittlement in the materials. The staff finds the applicant response acceptable, since it clarified that HNP either does not have the comparable GALL Report components, or that component does not receive fluences greater than 1×10^{17} n/cm^2. Also, the staff finds the applicant's response to be acceptable because the applicant committed to revise the LRA to add appropriate AMR lines on reduction of fracture toughness for the four components outside

the beltline region that are projected to have neutron fluences in excess of 1 x 10^{17} n/cm^2 ($E \geq$ 1.0 MeV) prior to the expiration of the period of extended operation. This will require a license renewal application amendment.

Question No. 3.1-FS-07

REQUEST
GALL Report, Volume 2, Items IV.D1-4 (R-01), IV.C2-21 (R-06), and IV.C2-21 (RP-31) list; instrument penetrations and primary side nozzles, safe ends, and welds; pressurizer instrumentation penetrations, heater sheaths and sleeves, heater bundle diaphragm plate, and manways and flanges; and piping, piping components and elements, respectively, made of nickel alloy or steel with nickel alloy cladding. The GALL Report recommends XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," for Class 1 components, XI.M2, "Water Chemistry," for PWR primary water, and provide a commitment in the FSAR supplement to comply with applicable NRC Orders for managing cracking due to PWSCC in reactor coolant for these components. These lines roll up to the GALL Report, Volume 1, Table 1, Line 31. Please explain why comparable line items for these components with their associated MEAP are not included in the LRA tables.

RESPONSE
The first sentence in the above question should read:

The GALL Report, Volume 2, Items IV.D1-4 (R-01), IV.C2-21 (R-06), and IV.C2-13 (RP-31)…

<u>IV.D1-4 (R-01)</u>
The HNP steam generators do not have nickel base alloy instrument penetrations, primary side nozzles, safe ends or welds.

<u>IV.C2-21 (R-06)</u>

The HNP pressurizer does not have nickel-alloy instrumentation penetrations, heater sheaths and sleeves, heater bundle diaphragm plate, and manways and flanges.

<u>IV.C2-13 (RP-31)</u>

Except for components which have been more appropriately aligned to the GALL Report, items IV.A2-12, IV.A2-19 and IV.C2-24, there are no nickel-alloy or steel with nickel-alloy cladding "piping, piping components and elements" which would align to this the GALL Report item.

STAFF EVALUATION
During the audit, The staff reviewed applicant’s license renewal AMR basis document for reactor vessel internals and other supporting documents and determined that the applicant appropriately identified those components that align to the GALL Report Table 1, item 31. Therefore, the staff finds the applicant’s response acceptable. This question is resolved.

Question No. 3.1-FS-09

REQUEST
GALL Report, Volume 2, items IV.A2-6 (R-78), IV.A2-7 (R-79), and IV.A2-8 (R-80) identifies cracking due stress corrosion cracking; loss of material due wear; loss of preload due to thermal effects, gasket creep, and self-loosening, respectively, as aging effects for stainless steel control rod drive head penetration flange bolting in air with reactor coolant leakage environment. The GALL Report recommends XI.M18, "Bolting Integrity" for managing these aging effects. These lines roll up to the GALL Report, Volume 1, Table 1, Line 52. Please explain why comparable line item for this MEAP is not included in the LRA tables.

RESPONSE
The reactor vessel head includes 65 Control Rod Drive Mechanism (CRDM) head penetration nozzles. Of these, 52 CRDM penetrations are used for actual CRDM's, 4 CRDM penetrations are used for the Core Exit Thermocouples (CET), 8 spare CRDM penetrations are capped with a Head Adapter Plug and 1 spare CRDM penetration is used for RVLIS piping. A CRDM Head Penetration Flange is welded to top of each CRDM Head Penetration Nozzle. The top of each CRDM Head Penetration Flange is externally threaded (male) to receive an internally threaded (female) CRDM assembly, CET assembly, head adapter plug or RVLIS adapter as applicable. These components are then seal welded to the head penetration flanges. A bolted flange is not used for any of the above described locations. Therefore, the GALL Report, Volume 2, items IV.A2-6 (R-78), IV.A2-7 (R-79), and IV.A2-8 (R-80) do not apply.

STAFF EVALUATION
The staff finds the applicant's response acceptable, since it explained that HNP does not use a bolted flange design for the comparable GALL Report items in Table 1, item 52. Thus, the applicant AMR line item in Item 52 of Table 1 in GALL, Revision 1, Volume 1 are not applicable to HNP. This question is resolved.

Question No. 3.1-FS-10

REQUEST
GALL Report, Volume 2, item IV.C2-11 (RP-11) identifies loss of material due to pitting, crevice, and galvanic corrosion as an aging effect for copper alloy piping, piping components, and piping elements in closed cycle cooling water environment. The GALL Report recommends XI.M21, "Closed-Cycle Cooling Water System," for managing this aging effect. This line rolls up to the GALL Report, Volume 1, Table 1, Line 54. Please explain why comparable line item for this MEAP is not included in the LRA tables.

RESPONSE
In the above question, the second sentence should read "…recommends XI.M21, Closed-Cycle Cooling Water System" for this aging effect".

The reactor coolant pumps lube oil coolers include copper alloy tubing with a component cooling water system (closed cycle cooling water) environment. However, the tubing has been identified as a copper nickel alloy with < 15% Zn. Loss of material due to pitting and crevice corrosion is not applicable because the EPRI Mechanical Tools state that these mechanisms are not applicable for copper alloys with zinc content less than 15%. Loss of material due to galvanic corrosion is not applicable because the copper alloy tubing is not in contact with a material that is higher in the galvanic series. Therefore, no aging effects are applicable for this material/environment and thus it is not appropriate to align this component with the GALL Report, Volume 2, item IV.C2-11 (RP-11). No other reactor coolant system component has been identified with this material/environment combination.

STAFF EVALUATION
The staff confirmed that the tubing material is a copper nickel alloy with < 15% Zn. Based on this determination the staff and found the applicant's claim that loss of material due to pitting, crevice, and galvanic corrosion is not applicable to this component to be acceptable because it is consistent with the staff's aging effect criteria for copper alloy materials with greater than 15% zinc alloying content, as cited in Table IX.C of the GALL Report, Revision 1, Volume 2. On these bases, the staff agrees with the applicant's determination that the corresponding AMR result line in the GALL Report is not applicable for HNP. This question is resolved.

Question No. 3.1-FS-11

REQUEST
GALL Report, Volume 2, item IV.C2-12 (RP-12) identifies loss of material due to selective leaching as an aging effect for copper alloy >15% Zn piping, piping components, and piping elements in closed cycle cooling water environment. The GALL Report recommends XI.M33, "Selective Leaching of Materials," for managing this aging effect. This line rolls up to the GALL Report, Volume 1, Table 1, Line 56. Please explain why comparable line item for this MEAP is not included in the LRA tables.

RESPONSE
In the above question, the second sentence should read "…recommends XI.M33, Selective Leaching of Material" for this aging effect".

The HNP Aging Management Review did not identify any copper alloy with > 15% Zn in a closed-cycle cooling water environment within the systems evaluated in Chapter IV of the GALL Report. Thus, the GALL Report, Volume 2, item IV.C2-12 (RP-12) does not apply.

STAFF EVALUATION
The staff finds the applicant response acceptable, since it confirms that HNP does not have any copper alloy component with > 15% Zn in a closed-cycle cooling water environment. On this basis, the staff finds that the applicant's determination that the corresponding AMR result line in the GALL Report is not applicable for HNP is valid because the HNP design does not include any piping or pressurizer components that are fabricated from high zinc content (i.e. > 15% Zn) copper alloy materials and are exposed to a closed-cycle cooling water environment. This question is resolved.

Question No. 3.1-FS-12

REQUEST
GALL Report, Volume 2, item IV.C2-16 (R-19) identifies cracking due to cyclic loading as an aging effect for stainless steel or steel pressurizer integral support in air with metal temperature up to 288°C (550°F) environment. The GALL Report recommends XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," for Class 1 components for managing this aging effect. This line rolls up to the GALL Report, Volume 1, Table 1, Line 61. Please explain why comparable line item for this MEAP is not included in the LRA tables.

RESPONSE
As stated in LRA Table 3.1.1, Item 3.1.1-61, page 3.1-30, cracking due to cyclic loading is not applicable to this specific pressurizer subcomponent. Although "cracking due to cyclic loading" has not been identified as an applicable aging effect/mechanism for this particular pressurizer subcomponent, the cracking aging effect for the pressurizer is managed by the ASME Inservice Inspection, Subsections IWB, IWC, and IWD Program as stated in the discussion of item 3.1.1-61 in Table 3.1.1 on page 3.1-30 of the LRA.

STAFF EVALUATION
The staff finds the applicant response acceptable, since it explained that the pressurizer subcomponents in air are not subject to cyclic loading and therefore, MEAP corresponds to the GALL Report, item IV.C2-16 is not applicable to HNP. In addition, the applicant has indicated in AMR item 3.1.1-61 that it credits its ASME Inservice Inspection, Subsections IWB, IWC, and IWD Program to manage any cracking that may occur in its pressurizer components, including the integral supports. This is independent of the aging mechanism inducing this aging effect. Thus, the applicant has adequate measures in place to manage any cracking that may initiate in pressurizer integral supports. This question is resolved.

Question No. 3.1-FS-14

REQUEST
GALL Report, Volume 2, item IV.A2-25 (R-78) identifies loss of material due to wear as an aging effect for vessel shell flange made of steel material in reactor coolant environment. The GALL Report recommends XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," for Class 1 components for managing this aging effect. This line rolls up to the GALL Report, Volume 1, Table 1, Line 63. Please explain why comparable line item for this MEAP is not included in the LRA tables.

RESPONSE
The first sentence should read “GALL Report, Volume 2, item IV.A2-25 (R-87) identifies…”

The HNP Aging Management Review included a review of operating experience. There is no history of wear on the HNP reactor flanges. Therefore wear is not identified as an aging effect for this component.

However, as identified in LRA Table 3.1.2-1, page 3.1-39, the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program will be used to manage cracking due to stress corrosion cracking for this component.

STAFF EVALUATION
The staff finds the applicant’s response acceptable because the applicant has clarified that its AMRs for the steel reactor vessel closure flange do include an appropriate AMR on management of cracking - stress corrosion cracking in the component even though the applicant has aligned this AMR to an AMR item in GALL (i.e., to GALL AMR IV.A2-11) other the IV.A2-25, and because the AMP that the applicant is crediting for management of this aging effect (i.e., the ASME Section XI Inservice Inspection Program) is the same AMP as is recommended in GALL AMR Item IV.A2-25. Based on this response, the staff finds the applicant’s AMR to be acceptable because it is consistent with GALL. This question is resolved.

Question No. 3.1-FS-16

REQUEST
LRA Table 3.1.2-6, on Page 3.1-147 identifies cracking due to SCC, loss of material due to crevice corrosion, and loss of material due to pitting corrosion as the aging effects for stainless steel steam generator tube support plates and flow distribution baffles in treated water (outside) environment. LRA specifies Steam Generator Tube Integrity and Water Chemistry programs for managing these aging effects. Although LRA uses note "F," which means material not in NUREG-1801 for this component, it refers to the GALL Report, item IV.D17 (R-42). Further, this is not consistent with the discussion for LRA Table 3.1.1, item 3.1.1-76 that states that "Ligament cracking due to corrosion of the steel steam generator tube support plate (Unique Item IV.D1-17) is not applicable to HNP. All tube support plates are made of type 405 ferritic stainless steel as described in FSAR Section 5.4.2.1.2."

(a) Please clarify the above discrepancy
(b) Please provide supporting documents and bases to demonstrate how Steam Generator Tube Integrity and Water Chemistry programs will manage the above listed aging effect for stainless steam generator tube support plates and flow distribution baffles in treated water

RESPONSE
As stated in LRA Table 3.1.2-6 (Page 3.1-147), the material for these components is "stainless steel." The GALL Report, item IV.D1-17 (R-42) identifies the material for the line item as "steel." As defined in GALL AMP IX.C (Pg. IX-12), the definition for "steel" does not include "stainless steel." Therefore, since the HNP material is not in NUREG-1801 for this component, the use of Note "F" is appropriate and is consistent with the discussion in LRA Table 3.1.1, item 3.1.1-76.

The aging management strategy for this component includes the Water Chemistry Program and Steam Generator Tube Integrity Programs. The Water Chemistry Program provides for monitoring and controlling of water chemistry using site procedures and processes for the prevention or mitigation of the loss of material and cracking aging effects. The Steam Generator Tube Integrity Program manages aging effects by providing a balance of prevention, inspection, evaluation, repair, and leakage monitoring.

STAFF EVALUATION
The GALL AMR item in question is AMR Item IV.D1-17 in the GALL Report, Revision 1, Volume 2. The GALL item pertains to the management of ligament cracking/corrosion in steel steam generator tube support plates. The staff finds the applicant response acceptable, since it explained that HNP steam generator tube support plates material is stainless steel and therefore, the AMR in AMR item IV.D1-17 of the GALL Report, Revision 1, Volume 2 is not applicable to the HNP. This question is resolved.

Question No. 3.1-FS-20

REQUEST
Shearon Harris Nuclear Power Plant (SHNPP) FSAR, Section 4.5.1.1, "Materials Specifications" (Page 4.5.1-1) states that all parts of the control rod dive mechanism (CRDM) that are exposed to reactor coolant are made of metals which resist the corrosive action of the water. Three types of materials are used exclusively: Stainless steel, nickel-chromium-iron, and cobalt based alloys. Further, FSAR Section 4.5.1.1 refers to other materials such as Haynes 25, Inconel X-750, ductile iron, and Dow Corning 302 for the coil stack assembly and latch assembly. However, most of these materials, except stainless steel, are not listed in LRA tables for CRDM assembly. Explain why these materials for CRDM are excluded from the LRA Section 3.1.

RESPONSE
Only the subcomponents of the CRDM having component intended functions were evaluated in the HNP Aging Management Review. Active sub-components are excluded from review based on 10 CFR 54.21(a)(1)(i). As stated in FSAR Section 4.5.1.1(a), "All pressure containing materials of the CRDM comply with Section III of the ASME Boiler and Pressure Vessel Code, and are fabricated from austenitic (Type 304) stainless steel." The pressure boundary components of the CRDM include only the "CRDM Latch Housings" and the "CRDM Rod Travel Housings" which are identified in FSAR Table 5.2.3-1 as type 304 stainless steel.

STAFF EVALUATION
The staff finds the applicant response acceptable, since it clarifies that the CRDM subcomponents with materials other than stainless steel either do not have an intended function or are not within the scope of an AMR because they are active components. Therefore, the staff concludes that only the stainless steel CRDM latch housings and CRDM travel housings have to be subject to an AMR in accordance with the applicant's scoping and screening methodology process. This question is resolved.

Question No. 3.1-FS-22

REQUEST
The discovery, in October 2006, of five circumferential indications of three Alloy 82/182 dissimilar metal welds (DMW) on the pressurizer at the Wolf Creek Generating Station raised safety concerns based on the size and location of the indications. Based on discussion with the NRC staff, licensee plants susceptible to this condition have committed to enhance inspection frequency and reactor coolant system leakage until actions to mitigate the potential of PWSCC in the affected welds have been completed.

Please briefly explain the commitments that you have made regarding the DMW on the pressurizer. Please explain what are your plans regarding the affected welds during the period of extended operation. Also, please explain your plans for mitigating or inspecting RCS locations with DMW , other than the pressurizer, that are potentially susceptible to PWSCC prior or during the period of extended operation.

RESPONSE
In a letter sent to the NRC (Serial HNP-07-015) on January 31, 2007, Progress Energy provided the following information:

> In October 2006, while performing inspections of pressurizer (PZR) Alloy 82/182 butt welds in accordance with MRP-139, a PWR licensee discovered several circumferential indications in the PZR surge, safety, and relief nozzles. Because of the potential importance of this issue, Carolina Power and Light Company (CP&L) doing business as Progress Energy Carolinas, Inc. commits to the following actions taken or planned at the Harris Nuclear Plant (HNP) for inspecting or mitigating Alloy 82/182 butt welds on PZR spray, surge and relief lines.
>
> Inspection of PZR Alloy 82/182 butt welds at HNP has not yet been completed, but HNP intends to complete all of the inspection and mitigation activities on these locations in refueling outage 14 (RFO-14) in the Fall 2007.
>
> Attachment 1 provides the results of completed inspections and the details of HNP's inspection and mitigation activities.
>
> Attachment 2 provides a discussion of reactor coolant system (RCS) leakage monitoring.
>
> Attachment 3 provides an example of the leakrate trend of unidentified RCS leakage.
>
> Attachment 4 provides the commitments to this letter. This document contains new or revised regulatory commitments.
>
> Future inspections of PZR Alloy 82/182 butt welds at HNP will be performed in accordance with industry guidance (MRP-139). The results of future inspections or mitigations of PZR Alloy 82/182 butt weld locations will be reported to the NRC within 60 days of startup from the outage during which they were performed.

The letter is available on the docket under Accession Number ML070370405.

STAFF EVALUATION

The staff finds the applicant response acceptable, since it provided the requested information for the HNP commitments and plans related to the inspection of the RCS Alloy 82/182 dissimilar metal welds. This question is resolved.

Question No. 3.1.FS-26

REQUEST
LRA Table 3.1.1 Item 3.1.1-23 (Page 3.1-20), under discussion column, states that the Flux Thimble Guide Tubes are aligned to item 3.1.1-30 (IV.B2-12) for cracking due to SCC. The GALL Report, item IV.A2-1, corresponding to Table 1 item 23 for bottom mounted instrument guide tubes, recommends a plant-specific AMP for this line item. However, the GALL Report Table 1, item 30 recommends water chemistry and a commitment by the applicant to follow industries development. LRA Table 3.1.2-1 refers to the GALL Report Table 1 item for flux thimble guide tubes and seals and shows it consistent (Note A) with the GALL Report, item IV.B2-12 and credits water chemistry for managing SCC aging effects for stainless steel Flux Thimble Guide Tubes and seals in treated water. Please provide bases for using the GALL Report, item IV.B-12 instead of the GALL Report, item IV.A2-1 for this line item.

Also justify crediting only water chemistry AMP for managing SCC aging effect for these components.

RESPONSE
All of the Bottom-Mounted Instrumentation (BMI) guide tubes are flux thimble guide tubes.

As stated in LRA 3.1.2.2.7.1, “The Flux Thimble Guide Tubes are aligned to item 3.1.1-30 (IV.B2-12) for cracking due to SCC. See further evaluation for Subsection 3.1.2.2.12.”

STAFF EVALUATION
The applicant’s response clarifies that the applicant has aligned its AMR on cracking of the flux thimble guide tubes to its AMR for the portions of the BMI guide tubes that are internal to the reactor vessel. The components referenced in this question are the portions of the guide tubes that are internal to the reactor vessel and the materials for these components are stainless steel. Therefore the staff finds that it is acceptable to align this AMR to GALL AMR IV.B2-12, and the Water Chemistry program is the acceptable program to credit along with a commitment for aging mangement of the RV internal components and to submit an inspection plan for these components to the NRC within 2 years of entering the period of extended operation. The staff has verified that the applicant has such a commitment in place in LRA Commitment No.

The staff also verified that the applicant does include appropriate AMRs on cracking - SCC of the portions of the BMI guide tubes (which are made from nickel alloy materials) that are welded to the exterior of the reactor vessel bottom head on page 3.1-56 of the LRA and that in its AMR, the applicant credits both the Water Chemistry Program and the ASME Section XI ISI Program to manage cracking is these external BMI guide tubes. This is acceptable because it is consistent with the staff’s appropriate AMR guidelines in GALL AMR IV.A2-19.

The staff finds the applicant response to be acceptable because the staff has verified that the applicant has both appropriate measures in place to manage cracking due to SCC in both the portions of the guide tubes that are both internal and external to the reactor vessel and because the program and commitments credited by the applicant are consistent with the staff’s recommendations in the GALL Report. This question is resolved.

Question No. 3.1-FS-28

REQUEST
LRA Table 3.1.2-6 (Page 3.1-138) identifies loss of material due to erosion as an aging effect for external surfaces of "Steam generator feedwater impingement plate and support" fabricated from carbon or low alloy steel in treated water. LRA uses Note E which indicates that HNP is consistent with the GALL Report Table 1, item 28 and the GALL Report, item IV.D1-13 (R-39) for component, material, environment and aging effect, but LRA does not credits the GALL Report's AMP. The GALL Report, item IV.D1-13 recommend using a plant-specific AMP that needs further evaluation. LRA credits One-Time Inspection AMP for managing loss of material due to erosion. Please provide bases for using OTI program for this line item. Please clearly explain how OTI manages steam generator feedwater impingement plate and support during the period of extended power.

RESPONSE
NRC Information Notice 97-88, “Experiences During Recent Steam Generator Inspections”, dated December 16, 1997 stated that in May 1997, “the licensee for the Shearon Harris Nuclear Power Plant found that four perforated, carbon steel ribs in a steam generator had been extensively damaged. The ribs are welded to the feedwater impingement plate which shields the steam generator tubes from direct impact of the feedwater flow. The licensee concluded that the high flow velocities of the feedwater eroded the ligaments between the perforations on the ribs.”

The Harris Westinghouse Replacement Model Delta 75 SGs do not have feedwater impingement plates as described in NRC IN 97-88. Impingement plates are associated with preheater model steam generators which were installed in the old Harris SG D4s.

The “impingement plates” identified in the LRA are ten (10) .25 inch thick carbon steel (ASME-SA-285, Gr. C) baffles which are located between the primary separator outer riser barrels and prevent direct impingement of feedwater onto the upper shell I.D.. There has been no operating experience identifying erosion of the baffles or supports. As stated in the One Time Inspections Program basis document, inspections should be scheduled no earlier than 10 years prior to the period of extended operation. HNP will have accumulated at least 30 years of use before inspections under this program begin, such that sufficient time will have elapsed for aging effects, if any, to be manifest. Therefore, the One-Time Inspection Program is adequate to verify the aging effect is not occurring.

STAFF EVALUATION
The applicant’s plant-specific operating experience is relevant to loss of material due to erosion in the impingement plates of the old HNP Model D4 steam generators. The applicant has replaced the old steam generators with new Westinghouse Model D-75 steam generators. These steam generators are not designed with the type of feedwater impingement plates in which the relevant operating experience has occurred and there is not any operating experience to date on loss of material due to erosion for the impingement plate design of the new steam generators. Therefore based on this assessment, the staff concludes that the One-Time Inspection Program is an appropriate program to credit to verify whether or not loss of material is an applicable aging effect for the feedwater impingement plate design of the new Model D-75 steam generators. The One Time Inspections program inspections will be adequate to verify if any loss of material due erosion is happening. This question is resolved.

Question No. 3.1-FS-31

REQUEST
Volumes 1 and 2 of the GALL Report, Revision 1 include applicable AMR items to manage cracking due to the various forms of stress corrosion cracking (SCC) in nickel alloy and stainless components in the reactor coolant coolant pressure boundary (RCPB). For aging management, the GALL Report recommends, in part, that the FSAR supplement should include a commitment to implement: (1) NRC Orders, Bulletins, and Generic Letters associated with nickel alloy components, and (2) staff-accepted industry guidelines. Based on its review of the AMR items on SCC in LRA Tables 3.1.2-1, -2, -3, -4, -5, and -6, the staff has determined that: (1) the LRA is either lacking AMRs to manage SCC in some nickel-alloy components of the RCPB, including nickel-alloy pressure boundary welds (i.e., bimetallic welds), or (2) that the existing AMR items for nickel alloy components of the RCPB do not include the applicable FSAR statement to implement: (1) NRC Orders, Bulletins, and Generic Letters associated with nickel alloy components, and (2) staff-accepted industry guidelines. The staff requests that the actions of the applicant:

a. Identify all nickel-alloy component and weld locations in the RCPB that are exposed to the reactor coolant, and clarify whether the LRA includes applicable AMRs on management of SCC or any of its forms (such as primary water stress corrosion cracking, etc.) in the components.

b. If it is determined that the LRA has omitted any applicable AMR entries on management of SCC (or its forms) in specific nickel alloy components or weld, amend the LRA to include the applicable AMRs.

c. Amend all of the applicable AMRs on SCC of nickel-alloy components or welds to include the commitment statement that is referenced for nickel-alloy AMR items in the GALL Report.

RESPONSE
a. As described in Progress Energy's Alloy 600 Strategic Plan the components/welds fabricated from nickel alloy are as follows:

Component	Number Per Unit
Pressure Safety and Relief Nozzle weld	4
Surge Nozzle SE weld	1
Spray Nozzle Safe End	1
CRDM Nozzle/Head	65

Component	Number Per Unit
CRDM Nozzle Weld	65
Head vent	1
Bottom head Inst. Penetration	52
Core Support Pads	4
Hot leg-to-RV weld	3
Cold leg-to-RV weld	3

b. LRA AMR table entries are required for the Pressurizer Spray Nozzle Safe End (page 3.1-121), Pressurizer Relief Nozzle Safe End (page 3.1-121), and Pressurizer Safety Nozzle Safe End (page 3.1-122). These AMR lines will include the cracking aging effect and refer to HNP's commitments to (1) NRC Orders, Bulletins, and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines.

An LRA amendment is required.

c. The HNP LRA currently contains commitments to (1) NRC Orders, Bulletins, and Generic Letters associated with nickel alloys and (2) staff-accepted industry guidelines. Reviews of the Table 2 items that roll up to the following Table 1 items (3.1.1-31, 3.1.1-34, and 3.1.1-35) demonstrate this. For example, Table 1 Item 3.1.1-31 on page 3.1-23 states:

"Consistent with NUREG-1801 with exception. The aging effect is managed by a combination of the Water Chemistry Program and the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program. The HNP commitment is described in the FSAR supplement. Further evaluation is documented in Subsection 3.1.2.2.13. The exception involves differences from the NUREG-1801 recommendations for the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program implementation."

In Subsection 3.1.2.2.13 (page 3.1-13) it states:

"In addition, HNP provides in the FSAR Supplement a commitment to comply with applicable NRC Orders and to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines."

In Appendix A (FSAR supplement) on page A-5 it states:

> "In accordance with the guidance of NUREG-1801, regarding activities for managing the aging of nickel alloy and nickel-clad components susceptible to primary water stress corrosion cracking, HNP will comply with applicable NRC Orders and will implement: (1) applicable Bulletins and Generic letters, and (2) staff-accepted industry guidelines."

The associated commitment discussed in the Table 1 item (Table 3.1.1) is applicable to all the Table 2 AMR lines in LRA Section 3.1 that roll up to it.

A License Renewal Application amendment is required.

STAFF EVALUATION

During the audit, The staff reviewed applicant's license renewal AMR basis document for reactor vessel internals and other supporting documents and determined that the applicant appropriately identified those components that align to the GALL Report Table 1, item 31. The staff has verified that the applicant has included the stated commitment in Commitment No. 2 of the LRA, as given in the applicant letter of November 14, 2006 (ADAMS ML063350267), and that the commitment appropriately references that the commitment is applicable to UFSAR Supplement Section A.1.1 of the LRA. Therefore, the staff finds the applicant's response acceptable because the applicant clarified which nickel alloy base metal and weld components need to be managed for SCC-initiated cracking and has credited both valid AMPs and a valid regulatory commitment to manage this aging effect in the nickel alloy components. The staff also finds this to be acceptable because it is consistent with the programs and commitments recommended by the staff for management of SCC-induced cracking in ASME Code Class 1 nickel alloy components, as provided in the staff's applicable AMRs on nickel alloy component cracking in Section IV of the GALL Report, Revision 1, Volume 2.

Question No. 3.1-FS-32

REQUEST
Volumes 1 and 2 of the GALL Report, Revision 1 include applicable AMR items to manage the aging effects that are applicable to reactor vessel internal (RVI) components made from nickel alloy and stainless steel materials. These aging effects include: (1) cracking due to stress corrosion cracking (SCC, including irradiation assisted stress corrosion cracking [IASCC]), (2) loss of fracture toughness due to neutron irradiation embrittlement or void swelling, (3) changes in dimension due to void swelling, and (4) loss of preload due to stress relaxation. To manage these aging effects, the GALL Report recommends that the FSAR supplement a commitment to: (1) participate in industry programs for investigating and managing the effects of aging on the RVI components, (2) evaluate and implement the results of the industry programs as applicable to the RVI components, and (3) upon completion of these program, but not less than 24 months prior to entering the period of extended, submit an inspection plan for the RVI components to the NRC for review and approval. Based on its review of the AMR items for the RVI components in LRA Table 3.1.2-1, the staff has determined that, while the AMR items do credit the appropriate aging management programs in the GALL Report, the AMR items do not include the applicable provision for the FSAR statement to include the applicable commitment. In order to ensure that aging management of the RVI components will be implemented in accordance with the recommendations of the applicable AMR items in the GALL Report, the staff requests that the applicant amend the applicable LRA AMR items appropriately to include the appropriate FSAR supplement commitment statement.

RESPONSE
The HNP LRA currently contains a 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. Reviews of the Table 2 items that roll up to the following Table 1 items (3.1.1-22, 3.1.1-24, 3.1.1-30, 3.1.1-33, and 3.1.1-37) demonstrate this. For example, Table 1 Item 3.1.1-22 on page 3.1-23 states:

> "The HNP commitment is described in the FSAR supplement. Further evaluation is documented in Subsection 3.1.2.2.6." In Subsection 3.1.2.2.6 (page 3.1-10) it states:
>
> > "HNP provides in the FSAR Supplement a commitment to: (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."
>
> In Appendix A (FSAR supplement) on page A-5 it states:
>
> > "In accordance with the guidance of NUREG-1801, regarding aging management of reactor vessel internals components for aging mechanisms, such as embrittlement and void swelling, HNP will: (1) participate in the industry programs for investigating and managing aging effects on reactor internals (such as Westinghouse Owner's Group and Electric Power Research Institute materials programs), (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."

The associated commitment discussed in the Table 1 item (Table 3.1.1) is applicable to all the Table 2 AMR lines in LRA Section 3.1 that roll up to it.

STAFF EVALUATION
The staff has verified that the applicant has included the stated commitment as Commitment No. 1 of the LRA as given in the applicant's letter or November 14, 2006 (ADAMS ML063350267) and that the commitment appropriately reflects that the commitment is applicable to UFSAR Supplement Section A.1.1 of the LRA. The staff finds the applicant's response to be acceptable because the staff has verified that the Commitment No. 1 in LRA and FSAR Section A.1.1 is applicable to AMRs on management of the cracking due to stress corrosion cracking (SCC, including irradiation assisted stress corrosion cracking [IASCC]), loss of fracture toughness due to neutron irradiation embrittlement or void swelling, changes in dimension due to void swelling, and loss of preload due to stress relaxation in the RV internals that are exposed to treated water. This question is resolved.

Question No. 3.1-FS-33

REQUEST
LRA, Table 3.1.2-4, page 3.1-111 lists carbon steel RCP Oil Cooler/Heat Exchanger Components in treated water environment. LRA identifies loss of material due to crevice, pitting, and general corrosion and credits Closed-Cycle Cooling Water Program for managing this aging effect. LRA shows consistency with the GALL Report, item IV.C2-14 (RP-10) and the GALL Report Table 1, item 53. Note B is used in the LRA. Note B indicates that the HNP program has an exception to the GALL Report program.

LRA B.2.11, "Closed-Cycle Cooling Water System Program," under program elements affected by the exception states that:

1. Parameters Monitored/Inspected

   Some heat exchangers are not monitored for flow, inlet and outlet temperatures, and differential pressure. In these cases, either the functionality of these heat exchangers is verified by activities outside the Closed-Cycle Cooling Water Program or the specific operating conditions of the heat exchanger render performance testing unreliable.

2. Detection of Aging Effects

   Some heat exchangers that are not normally in operation are not periodically tested to ensure operability. However, the functionality of these heat exchangers is verified by activities outside the Closed-Cycle Cooling Water Program.

Please clarify whether this exception is applicable to the RCP Oil Cooler/Heat Exchanger. If so, please explain how the functionality of these heat exchanged is verified.

RESPONSE
The RCP Oil Cooler/Heat Exchanger Components intended function is pressure boundary. These components serve to maintain pressure boundary integrity of the Component Cooling Water System. Therefore, verifying the functionality in relation to a heat transfer intended function is not required.

STAFF EVALUATION
The staff finds the applicant response acceptable, since it explained that functionality tests are only need for verifying the functionality of a heat transfer intended function and that such functionality testing is not applicable to the management of aging effects that could impact a pressure boundary function. Based on this assessment, the staff concludes that the applicant has provide a valid basis why functionality testing is not necessary for managing loss of material due to general, crevice, and pitting corrosion for the RCP oil cooler/heat exchanger components and for justifying that the exception to LRA B.2.11 is not applicable to these components. This question is resolved.

Question No. 3.1-FS-35

REQUEST
LRA Table 3.1.2-6 (Page 3.1-136) identifies loss of material due to flow accelerated corrosion (FAC) as an aging effect for the internal surfaces of "Feedwater Nozzle" fabricated from carbon or low alloy steel in treated water. LRA uses Note A which indicates that HNP is consistent with the GALL Report Table 1, item 59 (LRA listed 3.3.1-59, which appears to be a typo) and the GALL Report, item IV.D1-5 (R-37). The GALL Report, item IV.D1-5 identifies wall thinning due FAC. Please explain how LRA identified aging effect is consistent with the GALL Report for this line item.

RESPONSE
HNP considers the aging effects “wall thinning” and “loss of material” to be equivalent with respect to flow-accelerated corrosion.

The LRA will be amended to correct the typographical error identified in the above question.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds this response acceptable, since the applicant clarified that it considers wall thinning due to FAC equivalent to loss of material due to FAC. This question is resolved.

Question No. 3.1-FS-39

REQUEST
GALL Report, Volume 2, item IV.D1-22 (R-48) identifies cracking due to intergranular attack as an aging effect for nickel alloy steam generator tubes and sleeves in a secondary feedwater/steam environment. The GALL Report recommends XI.M19, "Steam Generator Tubing Integrity" and Chapter XI.M2, "Water Chemistry," for PWR secondary water for managing this aging effect. This line rolls up to the GALL Report, Volume 1, Table 1, Line 72. Please explain why comparable line item for this MEAP is not included in the LRA tables.

RESPONSE
For the purposes of AMR, the HNP AMR methodology for predicting the cracking aging effect does not distinguish between this intergranular attack and intergranular stress corrosion cracking. These AERMs are both captured as “cracking due to stress corrosion cracking. This AERM is managed by a combination of the Steam Generator Tube Integrity Program and the Water Chemistry Program (aligned to the GALL Report, Volume 2, item IV.D1-20) as shown on page 3.1-145 of the LRA. This is the same aging management strategy recommended in the GALL Report for Table 2, item IV.D1-22.

STAFF EVALUATION
The staff finds this response acceptable, since the applicant clarified that the aging effect mechanisms of intergranular attack and intergranular stress corrosion cracking are treated as the same aging effect mechanisms for cracking that is induced by stress corrosion and because the applicant is applying the Steam Generator Tube Integrity and the Water Chemistry Programs to manage this type of cracking in the surfaces of the steam generator tubes and sleeves that are exposed to a secondary feedwater/steam environment. The staff also finds this to be acceptable because the programs credited for aging management by the applicant are consistent with those recommended in the corresponding AMR items for these components, as given in either GALL AMR IV.D1-20 or GALL AMR IV.D1-22. This question is resolved.

Question No. 3.1-FS-43

REQUEST
LRA, Table 3.1.2-4, page 3.1-113 lists RCP Oil Spill Protection System Piping fabricated from carbon or low alloy steel internally exposed to Lubricating Oil or Hydraulic Fluid environment. Notes H is used for this line item. Note H indicates that aging effect is not the GALL Report for this component, material and environment combination. LRA credits Lubricating Oil Analysis B.2.25) and One-Time Inspection (B.2.18) programs for managing Loss of Material due to Galvanic Corrosion aging effect. It also lists the GALL Report item VII.G-26 (A-83) for this item. The aging effect identified for this GALL Report is loss of material due to general, pitting, and crevice corrosion. Please explain why GALL Report item VII.G-26 is referenced for this LRA line item. Please discuss how Lubricating Oil Analysis and One-Time Inspection programs manage loss of material due to galvanic corrosion (aging mechanism), since aging mechanisms are not defined in LRA B.2.18 and B.2.25.

RESPONSE
Please explain why GALL Report item VII.G 26 is referenced for this LRA line item.

GALL Report item VII.G 26 (A 83) is identified for this item because the component has been identified to be subject to loss of material due to general, pitting, and crevice corrosion. Since the component, material, and aging effects are the same as the GALL Report, the Standard Note “A” has been identified.

Please discuss how Lubricating Oil Analysis and One Time Inspection programs manage loss of material due to galvanic corrosion (aging mechanism), since aging mechanisms are not defined in LRA B.2.18 and B.2.25.

For this AMR line item, the environment is lubricating oil. The oil collection piping consists of both carbon steel and stainless steel sections of piping. Since carbon steel piping is connected to stainless steel piping and since the lubricating oil can potentially contain moisture, “galvanic corrosion” is identified as an aging mechanism. Consistent with the GALL Report, the Lubricating Oil Analysis Program “maintains oil systems contaminants (primarily water and particulates) within acceptable limits.” Therefore, since galvanic corrosion requires presence of an electrolyte for the mechanism to occur, the program is appropriate to manage the aging effect. No operating experience has been identified to suggest that loss of material has occurred for these components, therefore the One-Time Inspection Program is adequate to verify the aging effect is not occurring.

STAFF EVALUATION
The staff’s evaluation of the applicant’s Lubricating Oil Analysis Program and One-Time Inspection Program are documented in SER Section 3.0.3.2.18 and 3.0.3.1.5, respectively. The staff finds the applicant’s response acceptable, since it conservatively identified loss of material due to galvanic corrosion as an aging effect for the carbon or low alloy steel RCP oil spill protection system piping exposed to lubricating oil and that appropriately explained how this aging effect is managed by the HNP’s AMPs. With respect to loss of material induced by galvanic corrosion, two differential materials need to exist in piping segment and a medium (such or water) conducive of transporting an electrical current needs to be present. With respect to the AMPs credited by the applicant, the Lubricating Oil Analysis Program is designed to minimize the ingress of water and ionic particulates into the lubricating oil environment, thus minimizing the probability that water can be present in the oil and avoid the presence of an aqueous medium that could potentially lead to a galvanic current. The One-Time Inspection Program will be

used to verify that the Oil Analysis Program is achieving this function and that galvanic corrosion has not occurred in the applicable piping. This question is resolved.

Question No. 3.1-FS-44

REQUEST
The AMRs in the LRA include numerous AMRs that credit the TLAA on thermal fatigue with the management of "cracking due to thermal fatigue" in the components. The corresponding AMR items in the GALL Report refer to this aging effect as "cumulative fatigue damage," and recommends that the TLAA on Metal Fatigue be used to manage this aging effect. The TLAA on Metal Fatigue is not an acceptable means of aging management in a component If a fatigue crack has already initiated in the component. For these AMR items, clarify: (1) why the aging effect description (i.e, "cracking due to thermal fatigue") differs from that used in the GALL Report, and (2) why the TLAA on metal fatigue is considered to be capable of managing cracking due to thermal fatigue if fatigue-induced cracking has already initiated in the components.

RESPONSE
1. The terminology used in the HNP LRA is adopted from the EPRI Mechanical Tools. This methodology will identify this as a potential AERM under 2 conditions. First, if an explicit fatigue evaluation has been performed and is part of the current licensing basis. Second, when using the temperature screening criterion for piping and equipment designed to ASME Section III, Class 2 and 3 and ANSI B31.1 that account for fatigue through use of the stress range reduction factor, f. At this point in the AMR process, the AERM is used as a placeholder to indicate that further evaluation is required.

2. A TLAA on metal fatigue is not considered capable of managing cracking due to metal fatigue. After the process described in 1 above, the AMR process ends and the TLAA evaluation begins. LRA Section 4.3 documents the resolution of those AMR lines where the potential aging effect of cracking has been postulated.

3. This methodology was used for the Brunswick License Renewal project. The Safety Evaluation Report (page 3-185) addressed this issue as follows:

The applicant's supplemental response to RAI 3.1.2.3.1.1-1, Part B, clarified that the phrase "cracking due to thermal fatigue," as defined in the applicable AMR line items for "Table 2" in LRA Sections 3.1, 3.2, 3.3, 3.4, and 3.5, corresponds to the definition "cumulative fatigue damage" in the applicant AMR line items for "Table 1" in LRA Sections 3.1, 3.2, 3.3, 3.4, and 3.5. The applicant changed the terminology because it recognized that 10 CFR 54.21(a) requires that aging effects be managed for the period of extended operation and because the term "cumulative fatigue damage" referred to a parameter that is used to assess the aging effect of cracking due to thermal fatigue and was not referring to the aging effect itself. Based on this assessment, the change in the terminology from "cumulative fatigue damage" in the "Table 1" to "cracking due to thermal fatigue" in the "Table 2" was done to satisfy the provision and criteria of 10 CFR 54.21(a). This meets the provisions in SRP-LR Sections 3.1, 3.2, 3.3, 3.4, and 3.5 for assessing cracking due to thermal fatigue/cumulative fatigue damage in ASME Code Class 1, 2, and 3 components and any applicable NSR components that are required to have thermal fatigue assessments for license renewal and, therefore, is acceptable. Refer to SER Section 4.3 for the staff's assessment of those plant components that are required to have thermal fatigue analyses for the LRA.

STAFF EVALUATION
The staff finds the applicant response acceptable, the methodology that used in LRA tables regarding cumulative fatigues aging effect has been previously evaluated and accepted by the staff and that in the type "2" AMR tables for the application, the term "cracking due to thermal fatigue" provides the corresponding aging effect terminology to "cumulative fatigue damage" in the type "1" AMR tables for the application. This question is resolved.

Question No. 3.1-FS-50

REQUEST
The LRA includes several AMR items on loss of material due to pitting and crevice corrosion and on cracking due to stress corrosion cracking (SCC) in feedwater (FW) nozzle and auxiliary feedwater (AFW) nozzle thermal sleeves under exposure to treated water. The applicant credits the Water Chemistry Program and the One-time Inspection Program to manage these aging effects in the components. The staff has determined that the scope of AMP B.1.28, One-Time Inspection Program, as given in the LRA does not specifically identify the feedwater (FW) nozzle and auxiliary feedwater (AFW) nozzle thermal sleeves as being within the scope of the AMP. The staff requests that the actions:

A. Clarify whether on not there are any other AMPs credited for the LRA that provide for periodic examinations of these thermal sleeves. If there are alternate AMPs, provide your basis why it acceptable to credit the One-Time Inspection Program as the means of managing loss of material and cracking these thermal sleeves in lieu of the alternate AMPs. Amend AMP B.1.28, One-Time Inspection Program, to include the FW nozzle and AFW nozzle thermal sleeves within the scope of the AMP.

B. The staff is of the opinion that initiation of cracking or loss of material in the FW and AFW nozzle thermal sleeves may impact the ability of the thermal sleeves to protect the FW and AFW nozzles against the consequences of thermal cycling, and thus impact their M-6 thermal insulation function. Provide your technical basis for concluding that loss of material or cracking would not impact the M-6 thermal insulation function for these thermal sleeves.

RESPONSE
A. Loss of material from pitting and crevice corrosion and cracking from SCC of the feedwater nozzle thermal sleeves and auxiliary feedwater nozzle thermal sleeves are managed by a combination of the Water Chemistry Program and the One-Time Inspection Program. The Water Chemistry Program provides for monitoring and controlling of water chemistry using site procedures and processes for the prevention or mitigation of the subject aging effects. The One-Time Inspection Program provides an inspection that either verifies that unacceptable degradation is not occurring or triggers additional actions that assure the intended function of affected components will be maintained during the period of extended operation.

The basis document for the One-Time Inspection Program includes the feedwater nozzle thermal sleeves and auxiliary feedwater nozzle thermal sleeves in the one-time inspections to verify effectiveness of the Water Chemistry Program. This level of detail is not provided in the LRA AMP description.

B. The LRA and the basis documents for the Water Chemistry and One-Time Inspection Program will be amended/revised to include, for the feedwater and auxiliary feedwater nozzles' M-6 Function, the Water Chemistry and One-Time Inspection Programs to manage the aging effects.

A License Renewal Application amendment is required.

STAFF EVALUATION

The feedwater nozzle thermal sleeves and auxiliary feedwater thermal sleeves used in the applicant Model D-75 steam generator design are not ASME Code Class 2 or 3 components but do serve the functions of: (1) providing structural or seismic support (an M-4 function) to the feedwater nozzles and auxiliary feedwater nozzles to the steam generators, and (2) protecting the feedwater nozzles and auxiliary feedwater nozzles to the steam generators against the consequences of thermal cycling (an M-6 function). Although the materials for these thermal sleeves are made from nickel alloy materials, the components are categorized as not ASME Code Class 1 reactor coolant pressure boundary components and are not subject to exposure to borated treated water environment. Thus, these thermal sleeves are not within the scope of the applicant's commitment for management of cracking due to stress corrosion cracking (cracking - SCC) in ASME Code Class 1 nickel alloy base metal and welds components. There is not any operating experience with thermal sleeve degradation in Westinghouse Model D-75 steam generator designs. Thus, it is appropriate for the use its water chemistry program to manage potential loss of material due to pitting or crevice corrosion and cracking - SCC in these thermal sleeves and to credit its One-Time Inspection Program to confirm the effectiveness of the Water Chemistry Program in achieving in preventative/mitigative functions and to verify that these aging effects are not occurring in the thermal sleeves. During the audit, the staff reviewed the Water Chemistry Program and One-Time Inspection Program program element descriptions in the applicant's basis documents and determined that these programs are consistent with program element criteria in GALL AMP XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection," without exception. The staff finds the applicant's response acceptable because: (1) the applicant will use to Water Chemistry Program to manage loss of material due to pitting and crevice corrosion and cracking - SCC, (2) credit the One-Time Inspection Program to either verify that these aging effects have not occurred in the thermal sleeves or take appropriate corrective actions if the one-time does indicate that either of these aging effects are applicable to the thermal sleeves, and (2) has committed to revise the LRA and the basis documents for the FW and AFW nozzles thermal sleeves with thermal insulation intended function (M-6 Function) to include loss of material due to pitting and crevice corrosion and cracking - SCC as applicable aging effects and to credit the Water Chemistry and One-Time Inspection Programs to manage these cracking and loss of material aging effects. Based on this assessment, this question is resolved.

Question No. 3.1-FS-51

REQUEST
(Supplemental Question)

The applicant identifies that a one time inspection is credited to manage loss of material due to general, pitting, or crevice corrosion, and in some cases cracking due to SCC, in the following component commodity groups:

- steam generator feedwater impingement plate and support
- feedwater distribution ring and support
- feedwater distribution ring spray nozzles
- auxiliary feedwater internal spray pipe
- moisture separator assembly
- miscellaneous non-pressure boundary steam generator internals

a. For the steam generator feedwater impingement plate and support, feedwater distribution ring and support, feedwater distribution ring spray nozzles, auxiliary feewater internal spray pipe, the commodity groups are within the scope of AMP B.2.18, One-Time Inspection Program. Clarify whether on not there are any other AMPs in the LRA that provide for periodic examinations of these commodity groups. If there are alternate AMPs, provide your basis why it acceptable to credit the One-Time Inspection Program as the means for managing loss of material (and in some cases cracking) in these commodity groups in lieu of the alternate AMPs.

b. AMP B.2.18, One-Time Inspection Program, does not specify that the steam generator moisture separator assembly is within the scope the AMP. Clarify whether on not there are any other AMPs credited for the LRA that provide for periodic examinations of the steam generator moisture separator assembly. If there are alternate AMPs, provide your basis why it acceptable to credit the One-Time Inspection Program as the means of managing loss of material in this component in lieu of crediting these others AMPs. Amend AMP B.2.18, One-Time Inspection appropriately to include the steam generator moisture separator assembly within the scope of the AMP if the component is not currently within the scope of the AMP.

c. Define the specific steam generator commodity groups are being referred under your term "Miscellaneous Non-Pressure Boundary Internals." Provide your basis why it acceptable to credit the One-Time Inspection Program as the means for managing loss of material and cracking in each of these steam generator non-pressure boundary internals and amend AMP B.2.18, One-Time Inspection Program, to specifically place these non-pressure boundary internals as being with the scope of AMP B.2.18.

RESPONSE
Background – One-Time Inspection Program

The One-Time Inspection Program basis document provides a description of Program Scope by tabulating for each material/environment combination: system number/system name, and component inspected/description. Each table also provides aging effects and component intended functions.

a. The steam generator feedwater impingement plate and support, feedwater distribution ring and support, feedwater distribution ring spray nozzles, auxiliary feedwater internal spray pipe commodity groups are managed by the Water Chemistry Program and the One-Time Inspection Program.

For those components that are carbon steel, the aging effects managed are loss of material from pitting, crevice and general corrosion. For those components that are nickel based alloys, the aging effects managed are loss of material from pitting and crevice corrosion and cracking due to SCC.

The basis for why it acceptable to credit the Water Chemistry Program and the One-Time Inspection Program as the means for managing the subject aging effects is as follows:

Water Chemistry Program provides for monitoring and controlling of water chemistry using site procedures and processes for the prevention or mitigation of the subject aging effects. The One-Time Inspection Program provides an inspection that either verifies that unacceptable degradation is not occurring or triggers additional actions that assure the intended function of affected components will be maintained during the period of extended operation.

In addition to the prevention and mitigation of the aging effects provided by the Water Chemistry Program, the One Time Inspection Program will rely on established NDE techniques, including visual, and/or volumetric techniques that are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR 50, Appendix B. The inspection and test techniques will have a demonstrated history of effectiveness in detecting the aging effect of concern. Evidence of degradation will result in evaluation by Engineering for repair/replacement in accordance with the Corrective Action Program. Acceptance criteria will be based on construction code, manufacturer's recommendations, engineering evaluation, or metallurgical examination, as appropriate.

b. The steam generator moisture separator assembly commodity group is managed by the Water Chemistry Program and the One-Time Inspection Program. For the carbon steel steam generator moisture separator assembly, the aging effects managed are loss of material from pitting, crevice and general corrosion.

The basis for why it acceptable to credit the Water Chemistry Program and the One-Time Inspection Program as the means for managing the subject aging effects is as follows:

Water Chemistry Program provides for monitoring and controlling of water chemistry using site procedures and processes for the prevention or mitigation of the subject aging effects. The One-Time Inspection Program provides an inspection that either verifies that unacceptable degradation is not occurring or triggers additional actions that assure the intended function of affected components will be maintained during the period of extended operation.

In addition to the prevention and mitigation of the aging effects provided by the Water Chemistry Program, the One Time Inspection Program will rely on established NDE techniques, including visual, and/or volumetric techniques that are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR 50, Appendix B. The inspection and test techniques will have a demonstrated history of effectiveness in detecting the aging effect of

concern. Evidence of degradation will result in evaluation by Engineering for repair/replacement in accordance with the Corrective Action Program. Acceptance criteria will be based on construction code, manufacturer's recommendations, engineering evaluation, or metallurgical examination, as appropriate.

The basis document for the One-Time Inspection Program includes the subject components in the one-time inspections to verify effectiveness of the Water Chemistry Program. This level of detail is not provided in the LRA AMP description.

c. The steam generator Miscellaneous Non-Pressure Boundary Internals commodity group is managed by the Water Chemistry Program and the One-Time Inspection Program. For those components that are carbon steel, the aging effects managed are loss of material from pitting, crevice and general corrosion. For those components that are nickel based alloys or stainless steel, the aging effects managed are loss of material from pitting and crevice corrosion and cracking due to SCC.

Examples of the steam generator Miscellaneous Non-Pressure Boundary Internals include, primary separators, secondary separator vanes, various plates, stay rods and spacer pipes. These components will be added to the basis document Evaluation Group Tables.

The basis for why it acceptable to credit the Water Chemistry Program and the One-Time Inspection Program as the means for managing the subject aging effects is as follows:

Water Chemistry Program provides for monitoring and controlling of water chemistry using site procedures and processes for the prevention or mitigation of the subject aging effects. The One-Time Inspection Program provides an inspection that either verifies that unacceptable degradation is not occurring or triggers additional actions that assure the intended function of affected components will be maintained during the period of extended operation.

In addition to the prevention and mitigation of the aging effects provided by the Water Chemistry Program, the One Time Inspection Program will rely on established NDE techniques, including visual, and/or volumetric techniques that are performed by qualified personnel following procedures consistent with the ASME Code and 10 CFR 50, Appendix B. The inspection and test techniques will have a demonstrated history of effectiveness in detecting the aging effect of concern. Evidence of degradation will result in evaluation by Engineering for repair/replacement in accordance with the Corrective Action Program. Acceptance criteria will be based on construction code, manufacturer's recommendations, engineering evaluation, or metallurgical examination, as appropriate.

The basis document for the OneTime Inspection Program includes the subject components in the one-time inspections to verify effectiveness of the Water Chemistry Program. This level of detail is not provided in the LRA AMP description.

STAFF EVALUATION
The staff determined that the use of the Water Chemistry Program and the One Time Inspection Program will be adequate to manage: a) loss of material from pitting, crevice and general corrosion for carbon steel components, cracking due to SCC and loss of material from pitting, crevice and general corrosion for nickel based alloy components; b) loss of material from pitting, crevice and general corrosion for the carbon steel steam generator moisture separator assembly; and c) loss of material from pitting, crevice and general corrosion for carbon steel, and cracking due to SCC and loss of material from pitting, crevice and general

corrosion for nickel based alloy components identified as the steam generator Miscellaneous Non-Pressure Boundary Internals commodity group in the LRA Table 3.1.2-6.

Question No. 3.2.1-07-SA-01

REQUEST
Provide basis for crediting One-Time Inspection Program for aging management of stainless steel refuelling water storage tank exposed to raw water environment in containment spray system, (Table 3.2.2-1, page 3.2-29).

RESPONSE
LRA Table 3.2.2-1 for this line item refers to plant-specific note 214. This note states:

This line item represents corrosion resulting from water seepage underneath the Refueling Water Storage Tank. The tank area enclosure for the RWST does not drain automatically. Therefore standing rainwater may accumulate to levels above the tank pad elevation.

Chemistry procedures provide guidance on the sampling of drainage water before it is released from the Tank Area. Results of sampling for radioactive contamination will be reported to Operations. Operations will release the water to the storm drain system or return it for processing in the liquid radwaste system.

Due to the limited duration of accumulated water in this area, damage from this aging effect is not expected to be significant. There is no site operating experience identifying degradation on the external surface of this component. For this reason the One-Time Inspection Program was selected. If degradation is more than anticipated, then the item would be entered into the corrective actions program and additional activities, e.g. repair, replacement or additional inspections, would address those concerns.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant credited One-Time Inspection Program to ensure that an aging effect is not occurring for stainless steel refuelling water storage tank exposed to raw water seepage underneath the tank environment. There is no site operating experience identifying degradation on the external surface of the tank. Due to the limited duration of accumulated water underneath the Refueling Water Storage Tank, the staff concludes that implementation of this program provides a high level of assurance that the components intended function will be maintained within CLB for the extended period of operation.

Question No. 3.2.1-27-SA-01

REQUEST
In Table 3.2.1, item 3.2.1-27, aging effect is listed as loss of material due to general, pitting, crevice, and galvanic corrosion; for the corresponding items in Table 3.2.2-3, page 3.2-35 aging effect requiring management is annotated as loss of material due to general, pitting, and crevice corrosion. Provide justification for not including galvanic corrosion under the aging effect requiring management in Table 3.2.2-3.

RESPONSE
HNP methodology predicts galvanic corrosion when a component/commodity is electrolytically connected to a dissimilar material. In the case of the RHR Heat Exchanger Components, this component/commodity is not electrolytically connected to a dissimilar material.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the steel heat exchangers do not have dissimilar materials for galvanic corrosion to occur and act as an aging mechanism. The staff concludes that the applicant has correctly identified aging effect requiring management as loss of material due to crevice, general, and pitting corrosion for steel heat exchanger components when exposed to treated water. Applicant takes credit for Closed-Cycle Cooling Water System Program to manage the aging effects. Implementation of this program provides a high level of assurance that the components intended function will be maintained within CLB for the extended period of operation. This question is resolved.

Question No. 3.2.2-01-SA-01

REQUEST
Provide basis for including piping insulation as component requiring aging management in Tables 3.2.2-1, 3.2.2-2, and 3.2.2-3.

RESPONSE
The identification of piping insulation as a component requiring aging management has been addressed generically during the scoping and screening audit. The inclusion of the piping insulation is based on a whether insulation has been included in the current licensing bases (CLB). For example, the areas that warranted research in the HNP licensing basis are as follows:

i) Thermal insulation credited in room cooler evaluations and

ii) Thermal insulation required for environmental control these evaluations could be from statements made in the FSAR or as a basis for the safety related HVAC calculations.

iii) FSAR references to the use of insulation.

iv) Review Design Basis Documents on the Treatment of Insulation

The license renewal basis document for piping insulation will be available for review during the AMR audit.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant included the piping insulation as the thermal insulation was credited in design basis for room cooler evaluations. The staff concludes that the applicant has correctly identified insulation in scoping and screening section; however, there is no aging effect requiring management because air does not have an aging effect on insulation cover which is normally steel or aluminum. The GALL Report does not address thermal insulation exposed to air as a component or material that requires aging management during the period of extended operation. This is acceptable because this amounts to a conservative approach taken by the applicant and goes beyond the recommendations in the GALL Report. This question is resolved.

Question No. 3.2.2-01-SA-02

REQUEST
Provide basis for crediting One-Time Inspection Program for management of aging effects (loss of material due to crevice corrosion, general corrosion, and pitting corrosion) of carbon or low alloy steel piping, piping components, and piping elements exposed to air/gas (wetted) (inside) environment in containment spray system, (Table 3.2.2-1, page 3.2-28)

RESPONSE
This line item represents the internal surface of carbon steel nitrogen supply piping to the Containment Spray Additive Tank. Corrosion is not expected to occur since a nitrogen blanket is maintained which prevents degradation.

The LRA will be amended to identify that this line item (Table 3.2.2-1, page 3.2-28) will be managed by the One Time Inspection Program and the Water Chemistry Program.

The Water Chemistry Program provides for monitoring and controlling of water chemistry using site procedures and processes for the prevention or mitigation of the loss of material aging effect. The One-Time Inspection Program provides an inspection that either verifies that unacceptable degradation is not occurring or triggers additional actions that assure the intended function of affected components will be maintained during the period of extended operation.

A License Renewal Application amendment is required.

STAFF EVALUATION
This question has been closed to general RAI 3.2.1, Part C on management of loss of material due to general, pitting, and crevice corrosion in steel containment isolation components exposed to treated water.

Question No. 3.3.1-10-MK-01

REQUEST
Please confirm that there is no high strength steel bolting in the auxiliary systems.

RESPONSE
High strength steel bolts were not identified during the HNP aging management review for auxiliary systems.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that there is no high strength steel bolting in the HNP auxiliary systems. This explains why this Table 3.3.1 item is not used in the LRA. This question is resolved.

Question No. 3.3.1-13-MK-01

REQUEST
On page 3.5-139, HNP is using Water Chemistry Program to manage the loss of material (boral) for the spent fuel storage rack component type. In the Water Chemistry Program, there is no detection program element that would detect the loss of material for this component type. Please describe how the loss of material will be detected.

RESPONSE
HNP agrees that in the Water Chemistry Program, there is no detection program element that would detect loss of material for boral. However, assignment of Standard Note I indicated that aging effects in NUREG-1801 are not applicable. An evaluation for boral with regard to operating experience has determined that there has been no adverse HNP operating experience recorded. Additionally, both the V.C. Summer Nuclear Plant and the Brunswick Steam Electric Plant have been evaluated by the staff for these aging effects, and the Safety Evaluation Reports for License Renewal for these plants has determined the aging effects to be insignificant.

An amendment to the LRA is required based on this response. The LRA and the basis document will be amended to show that the HNP evaluation concluded that boral has no aging effects and therefore requires no aging management. The LRA and basis document plant-specific note for the boral line item will be revised to clarify that boral material has no aging effects and therefore requires no aging management.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that the use of a note I was intended to indicate that the aging effects in the GALL Report are not applicable. Furthermore, the applicant has explained that the operating experience reviews have determined that there is no age related degradation identified for this material and environment combination. Therefore, the LRA will be amended to show that the evaluation concluded that boral has no aging effects in this environment and therefore requires no aging management. The staff finds this acceptable based on industry and plant-specific operating experience. This question is resolved.

Question No. 3.3.1-21-CM-01

REQUEST
In LRA Table 3.3.1 on page 3.3-88, item 3.3.1-21 for AMR component steel heat exchanger components exposed to lubricating oil, identifies microbiologically-influenced corrosion (MIC) as an aging mechanism requiring aging management. LRA Table 3.3.2-17 on page 3.3-216 for diesel engine governor oil cooler components, material carbon steel, does not identify MIC as an aging mechanism. Further NUREG-1801, Volume 2, Table VII.H2-5, also identifies MIC as an aging mechanism for steel in lubricating oil. Explain how MIC is managed for steel heat exchanger components in lubricating oil. MIC is also absent for steel heat exchanger components in LRA Table 3.3.2-19 on page 3.3-229.

RESPONSE
HNP methodology does not assume lubricating oil contains a source of MIC. This is based on the discussion in Appendix C, Section 3.1.6 of EPRI Report TR-1003056, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 3, which states:

> While MIC contamination is possible in lubricating oil applications, the likelihood of MIC causing extensive damage in lube oil systems is minimal. Even if contamination of the oil occurs, the relatively clean systems and addition of corrosion inhibitors to the lubrication oil does not provide an environment conducive to microorganism growth. The potential for MIC growth and subsequent corrosion effects in lube oil systems appears to be very small based on the addition of lube oil corrosion additives, oil purity testing programs and the extremely low likelihood of lube oil contamination. Even if MIC were to be introduced into these systems, the sampling programs are likely to detect and correct the situation prior to MIC causing any appreciable corrosion of lube oil system components.

STAFF EVALUATION
The staff has verified that LRA Table 3.3.2-19 does include AMRs on loss of material of the carbon steel/alloy steel lube oil cooler components that are exposed to a lubricating oil environment and that these AMRs credit both the Lubricating Oil Analysis Program and the One-Time Inspection Program to manage loss of material in these components. The staff determined that the applicant’s main argument in responding to this question is that, even though MIC is not listed as a mechanism that can lead to loss of material in these components, the introduction of corrosion inhibitors could preclude the occurrence of MIC in the system. From the staff’s perspective, the staff finds that it is even more important that the applicant has also credited in One-Time Inspection Program to manage loss of material in these components because the One-Time Inspection Program will either verify that the Lubricating Oil Analysis Program is achieving its purpose of precluding MIC growth and that MIC-induced loss of material is not occurring in the components, or else propose appropriate corrective actions if it is determined that MIC-induced loss of material is occurring in the components. Based on this review, the staff finds the applicant's response acceptable because the One-Time Inspection Program will be used to verify effectiveness of the Lubricating Oil Analysis Program in achieving its mitigative function for precluding MIC in these lubricating oil-based systems.

Question No. 3.3.1-25-CM-01

REQUEST
In LRA Table 3.3.1 on page 3.3-88, item 3.3.1-25 for AMR component copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external), identifies that HNP AMR methodology does not predict aging effects in absence of contaminants. Explain why HNP does not expect contaminants to be present for this component type.

Following original response to the above question the following additional information is required:

> During a conversation with a member of the Progress Energy License Renewal Team, a discussion about the copper alloy HVAC Components Exposed to Condensation took place. The staff asked which specific HNP HVAC components are applicable to Table 1 item 3.3.1-25. The applicant explained that the specific components that are applicable to Table 1 item 3.3.1-25 are the actual cooling coils within the HVAC unit. The License Renewal Team member also explained that because there are no flat areas where contaminants may collect no stagnant pool or puddle of condensation would raise the local concentration of contaminants which would cause loss of material.

Please answer the following about the Table 1 item 3.3.1-25:

a. Confirm that no HNP copper alloy HVAC components exposed to condensation other than the cooling coils exist, including cooling water piping and refrigerant piping that admits the coolant to the cooling coils.

b. Confirm that there are no flat areas on the HNP copper alloy HVAC components exposed to condensation including those areas created by finned tubes.

RESPONSE
In LRA Table 3.3.1 on page 3.3-89 for item 3.3.1-25, the referenced LRA Section 3.3.2.2.10.3 addresses this concern.

3.3.2.2.10.3 Copper Alloy HVAC Components Exposed to Condensation

For copper alloy with a zinc content of less than 15%, the HNP AMR methodology does not predict aging effects in the absence of contaminants. In the HNP ventilation systems, condensation is present but is drained away as it is formed on the cooling coil. This inhibits the concentration of contaminants.

HNP methodology does not require the mere presence of contaminants, but that they are capable of concentrating. Since condensation on cooling coils is frequent, there is little chance for the contaminants to concentrate.

The above position is supported by site operating experience described in the basis documents. A further discussion with system engineers regarding cooling coil leakage experience at HNP reveals no leakage from cooling coils that was initiated by external degradation due to aging effects/mechanisms.

STAFF EVALUATION

The staff finds the applicant's response acceptable because it stated that the copper alloy HVAC components exposed to condensation are the actual cooling coils within the HVAC unit. Additionally, the applicant stated that because there are no flat areas where contaminants may collect because a stagnant pool or puddle of condensation would raise the local concentration of contaminants, there are no aging effects. Further, the applicant explained that the design of the HVAC cooling coils preclude pooling of water by permitting free drainage from the tube exterior to the floor drains of the HVAC system. In addition, filtration elements are within the scope of license renewal which effectively removes the contaminants that could promote loss of material. The filters are changed frequently as they are short-lived components. Further, the applicant provided operating experience evidence that shows no age related degradation for copper alloy HVAC piping, piping components, and piping elements exposed to condensation (external). Therefore, the staff finds the response to 3.3.1-25 acceptable. Therefore, this question is resolved.

Question No. 3.3.1-32-CM-01

REQUEST
In LRA Table 3.3.2-22 on page 3.3-251 for AMR component type piping, piping components, and piping elements, material Copper Alloy >15% Zn, environment Fuel oil (Inside), Note D is referenced. Note D states that component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to the GALL Report AMP. Explain what component within Piping, piping components, causes this note to be used instead of Note B.

RESPONSE
HNP methodology generally treats the consistency determination of any typically similar component group as being inconsistent in a system that is not described in NUREG-1801 or when aligning to a NUREG-1801, Volume 2 table line for a system in a different Chapter or Section. This is considered a conservative approach in making standard note determinations. In this case a pipe in the Security Power System is considered different from a pipe in Section VII.H2, which is for the Emergency Diesel Generator System. NUREG-1801 does not contain a system identified as the Security Power System. Clearly there are differences in the actual operation, testing requirements, and environments to which these systems are subjected. Consequently, operating experience may differ. In Table 3.3.2-22, fuel oil components are considered similar to Section VII.H1, Diesel Fuel Oil System, in which case notes A or B were considered acceptable choices.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it adequately explains that GALL Report item VII.H2 for the emergency diesel generator system is referenced for use in the security power system component type piping, piping components, and piping elements and that the aging effects are managed by the Fuel Oil Chemistry and One-Time Inspection Programs. Additionally, the applicant identified that the security power system components in LRA Table 3.3.2-22 are more closely associated with GALL Report item VII.H2 than GALL Report item VII.H1 for the fuel oil system due to plant configuration. Therefore, this question is resolved.

Question No. 3.3.1-33-CM-01

REQUEST
In LRA Table 3.1.2-4 for AMR component RCP oil spill protection system piping, material stainless steel in a lubricating or hydraulic fluid (inside) environment Note A is referenced which claims consistency with GALL Report item VII.G-18. The GALL Report includes as aging effects requiring management (AERM) LOM due to crevice corrosion, LOM due to pitting, and LOM due to MIC. The aging effects in Table 3.1.2-4 do not include MIC. Additionally, further evaluation 3.3.2.2.12.2 refers to MIC as an AERM. Discuss whether MIC will be managed for this component, material, and environment in Table 3.1.2-4. MIC is also absent for stainless steel components in lubricating oil in Tables 3.3.2-1, 14, 19, 22, 27, and 32 on pages 3.3-119, -202, -231, -254, -287, respectively.

RESPONSE
The HNP methodology does not assume lubricating oil contains a source of MIC. See the detailed response provided for Question 3.3.1-21-CM-01 for additional information.

STAFF EVALUATION
The staff's evaluation of the applicant's response to Audit Question 3.3.1-21-CM-01 is applicable to the evaluation of the applicant's response to this question. Based on the staff's evaluation of Audit Question 3.3.1-21-CM-01, this question is resolved.

Question No. 3.3.1-34-CM-01

REQUEST
In LRA Tables 3.3.2-53, -56, -57, -58, -59, -60, -61, -62, -63, -64, -65, -66, -67, and -71 on pages 3.3-363, -371, -375, -381, -385, -388, -391, -397, -401, -403, -412, -416, -420, and -438 for AMR component elastomer seals and components, material elastomer in air-indoor or air/gas environments, Note E is referenced. Note E states: Consistent with NUREG-1801 item for material, environment, and aging effect, but a different AMP is credited or NUREG-1801 identifies a plant-specific AMP. For each of the elastomer seals identified above, explain why Note E was used for the existing and new AMPs used to manage LOM due to wear.

RESPONSE
NUREG-1800, Rev. 1, Section 3.0.1, "Background on Types of Reviews," on page 3.0-3, states:

> A portion of the AMR includes the assessment of the AMPs in the GALL Report. The applicant may choose to use an AMP that is consistent with the GALL Report AMP, or may choose a plant-specific AMP.

When performing the AMR for elastomer seals and components in air-indoor or air/gas environments subject to wear, the HNP License Renewal project selected NUREG-1801 (i.e., the GALL Report) aging management evaluation for auxiliary systems, Item 3.3.1-34. This item recommends that a plant-specific AMP be employed to manage loss of material due to wear of elastomer seals and components. As discussed in Appendix B, Subsection B.1.1, of the HNP LRA, the AMPs employed for license renewal at HNP are GALL Report AMPs; HNP does not employ any plant-specific AMPs. Therefore, when aligning HNP AMPs with GALL Report item 3.3.1-34, the GALL Report AMPs were used to address wear of elastomer components. The selected GALL Report AMPs were the External Surfaces Monitoring Program and the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. Because this differed from the recommended plant-specific AMP, Note E was selected to signify that a different AMP was being employed.

Note that HNP is preparing a plant-specific AMP for high-voltage, oil-filled cables as a result of the findings from the recent NRC audit of AMPs at HNP.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it adequately explains that although the GALL Report recommends that a plant-specific AMP be evaluated, a different AMP was used to manage the aging effects for elastomers. Therefore, the LRA line items described, indicate Note E. Additionally, this AMP was evaluated and found to adequately manage the aging effects of elastomers. Therefore, this question is closed.

Question No. 3.3.1-39-CM-01

REQUEST
In LRA Table 3.5.2-17 on page 3.5-139 for AMR spent fuel storage rack, material stainless steel in a treated water environment, Note I and plant-specific Note 560 is referenced. Note 560 states that: cracking due to SCC is not an applicable aging effect due to temperature of the fuel pool water being maintained below 140°F. Note I states that: aging effects are not applicable. Provide the HNP AMR methodology where this conclusion is substantiated including provisions for maintaining and monitoring fuel pool water temperature.

RESPONSE
The HNP material/environment aging effect evaluation has determined that Stress Corrosion Cracking (SSC) for stainless steel located in a treated water environment is not an aging mechanism below 140°F, which is consistent with NUREG-1801, Volume 1 Table 3 Items 39 and 90.

The Spent Fuel Pool Cooling and Related Systems review has determined that the HNP normal operating spent pool temperature is limited to a maximum temperature of 125.7°F, as stated in Note 560 on LRA page 3.5-203. The basis document, with the HNP AMR methodology, which concluded that aging effects are not applicable, and the references which provide for maintaining and monitoring spent fuel pool water temperature are available for review at HNP.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it adequately explains that the spent fuel pool temperature is not expected to rise above the threshold for the initiation of SCC. This is acceptable because it is in conformance with the staff's temperature threshold for initiating SCC-induced cracking in stainless steel materials, as given in Table IX.D of the GALL Report, Revision 1, Volume 2, for borated treated water>60°C (>140°F). Therefore, this question is closed.

Question No. 3.3.1-40-CM-01

REQUEST
In LRA Table 3.3.2-27 on page 3.3-270 for AMR fuel oil tank flame arrestors, material carbon or low alloy steel in an air–outdoor (outside) environment, Note E is referenced. Note E states that: this AMP is consistent with NUREG-1801 item for material, environment, and aging effect, but a different AMP is credited or NUREG-1801 identifies a plant-specific AMP. Further, the NUREG-1801, Volume 2 item is VII.H1-11 which is for the external surfaces of the component. The AMP identified for this component is Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components. Clarify whether this AMP is being applied to the external surfaces of this component.

RESPONSE
In this case the AMP is being applied to the external surface. Maintenance performed on relatively small components such as a flame arrestor is capable of adequately observing the condition of the external surfaces as well as the internal surface. Observation of the external surface would occur in the course of work to clean and inspect the internal components (e.g., during disassembly and reassembly). Consequently, the condition of the entire component both interior and exterior surfaces is considered as part of the maintenance activity.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it adequately explains how Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program (which is used to monitor for degradation in the inside surfaces of miscellaneous pipes and ductworks) can be used to monitor for degradation that may occur in the external surfaces these fuel oil tank flame arrestors. The staff finds the applicant’s response to be acceptable because the applicant has clarified that it would have to disassemble these components in order to be capable of inspecting their inside surfaces in accordance with the applicant’s Inspection of Internal Surfaces in Miscellanious Piping and Ducting Components Program and that the external surfaces would be looked at as part of the observation process that occurs during the disassembly process. This provides an adequate for crediting this program to manage loss of material due to general, pitting, and crevice corrosion in these flame arrestors. This question is resolved.

Question No. 3.3.1-42-CM-01

REQUEST
In LRA Table 3.3.1, item 3.3.1-42 on page 3.3-93 for AMR steel closure bolting exposed to air with steam or water leakage discusses that the AMR methodology for steel (surface temperature <212°F) always predicts crevice and pitting corrosion in addition to general corrosion in accordance with Item 3.3.1-43. Item 3.3.1-42 is not used in the HNP LRA. Clarify how general corrosion is managed for carbon or low alloy steel closure bolting in an air with steam or water leakage environment.

RESPONSE
The aging effect is managed by the Bolting Integrity Program as noted in Item 3.3.1-43. HNP methodology conservatively identifies the bounding set of aging mechanisms because the determination of when general corrosion occurs without any crevice or pitting corrosion is beyond the fidelity in the underlying science. Therefore, Item 3.3.1-42 was not used and Item 3.3.1-43 was consistently referenced in lieu of 3.3.1-42. The description in NUREG-1801, Section XI.M18 supports the applicability of the program for managing the subject aging effects. It states:

> The program generally includes periodic inspection of closure bolting for indication of loss of preload, cracking, and loss of material due to corrosion, rust, etc.

STAFF EVALUATION
The staff finds the applicant's response acceptable because it adequately explains that the Bolting Integrity Program is conservative with respect to the aging mechanisms described in the GALL Report. and because the Bolting Integrity Program is the typical program that is recommended in GALL for management of loss of material due to general, pitting, and crevice corrosion and cracking due to stress corrosion cracking in plant-specific bolting components. This question is resolved.

Question No. 3.3.1-50-MK-01

REQUEST
This Table 3.3.1 item 3.3.1-50 is being used to manage loss of material due to crevice and pitting corrosion for stainless steel piping, pipe components, and pipe elements in the fire protection system using the Closed Cycle Cooling Water System Program. Please describe how this aging effect will be managed by this AMP for this component type.

RESPONSE
The piping components in this group are associated with the Diesel Driven Fire Pump engine coolant system. HNP's methodology considered treated water consistent with the closed-cycle cooling water environment in NUREG-1801 as described in LRA page 3.0-11. This is supported by the Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, EPRI TR-1003056, Revision 3, which states in Section 2.2 of Appendix A.

> "Some of the PWR systems that contain non-borated treated water include main feedwater, main steam, intermediate or closed cooling systems, makeup water, emergency feedwater, and diesel jacket cooling water (typically with an ethylene glycol mix)."

As noted NUREG-1801, Section VII.H2, the Closed Cycle Cooling Water System Program can adequately manage the aging effects for this commodity group.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that the fluid in the diesel driven fire pump engine coolant system was considered as treated water consistent with the closed-cycle cooling water environment in the GALL Report. With this clarification, the staff agrees that the Closed-Cycle Cooling Water System Program can adequately manage the aging effects for this component type. This question is resolved.

Question No. 3.3.1-70-MK-01

REQUEST
In LRA Table 3.3.2-27, copper alloy spray nozzles and sprinkler heads exposed to raw water (Inside) environment with an intended function of M-8 (Spray Pattern) do not have an aging effect of fouling listed as an aging effect requiring management. Please explain why fouling is not consider an aging effect requiring management for these component types exposed to raw water.

RESPONSE
The aging effect flow blockage was applied to the steel piping system and not the sprinkler heads themselves, which normally experiences no water while in standby and are free of debris based on the piping configuration. Flow Blockage due to fouling will be added to the external environment of Spray nozzles and Sprinkler heads based on Industry OE. The Inspection of External Surfaces Program will address the sprinkler heads and the Fire Water System Program will address spray nozzles. An enhancement will be added for in-scope spray nozzles to either 1) add a requirement to perform flow testing to ensure proper spray pattern or add a modification to prevent blockage from external sources.

The selection of aging effects was meant to represent the actual condition of the equipment so that program activity and resources are focused on where they are most needed. Partial or full flow blockage, if present, would be expected elsewhere in the system such in pumps, valves, strainers, and long piping headers that normally experience stagnant flow conditions. Most of the sprinkler systems that are in scope are dry sprinkler systems and only periodically wetted during testing or actuation of the preaction/deluge valves. Some sprinkler systems in the Waste Processing Building are wet systems.

The geometry of the copper alloy sprinkler heads are arranged so they are not likely to foul. The sprinkler heads or inlet piping configuration typically extends from the top of the headers so sediment or other debris will not settle in them. Similar arguments can be made for nozzles which are open at the end of the steel piping systems and typically arranged so that sediment or debris will not accumulate in them.

As noted above, Flow Blockage due to Fouling needs to be addressed in piping headers and pumps that supply water to sprinkler heads and nozzles. Flow Blockage due to Fouling is an aging effect/mechanism associated with the entire water supply system. For example see other the piping components subjected to a Raw Water (Inside) environment in LRA Table 3.3.2-27. Flow testing, periodically cleaning system strainers, and other periodic operation of the systems and/or inspections are included in the Fire Water System Program. These program activities ensure that the supply headers are capable of supplying water under adequate pressure to the hose stations, nozzles and sprinkler heads and will be free of debris that could cause flow blockage at the sprinkler heads and nozzles.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has clarified that the basis for excluding this aging mechanism was the fact that the system is only periodically wetted so that there is no opportunity for fouling to occur. However, during the development of the response to this question, the applicant re-reviewed the industry plant operating experience and determined that flow blockage due to fouling should be added to the external environment of

spray nozzles and sprinkler heads. Based on industry operating experience, the staff finds this acceptable. An LRA amendment is required to incorporate these changes. This question is resolved.

Question No. 3.3.1-76-MK-01

REQUEST
In the following LRA Tables 3.3.2-06, 3.3.2-07, 3.3.2-08, 3.3.2-09, 3.3.2-10 and 3.3.2-34, Table 1 line item 3.3.1-76 is used to manage loss of material for the following carbon or low alloy steel component types: buried piping, piping components, and piping elements; normal service water pumps; normal service water seal and bearing water booster pumps; piping, piping components, and piping elements; and system strainers as well as gray cast iron fire service screen wash pumps; normal service water pumps; and piping, piping components, and piping elements exposed to raw water with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components or the External Surfaces Monitoring Program. Please explain the basis for adequately managing this aging effect without the benefit of the preventive measures provided by a program such as the Open Cycle Cooling Water Program.

RESPONSE
Questions 3.3.1-76-MK-01, 3.3.1-79-MK-01, 3.3.1-80-MK-01, and 3.3.1-81-MK-01 have a common theme and will be answered in the response to 3.3.1-76-MK-01. The response to these questions requires the answer to "Please explain the basis for adequately managing this aging effect without the benefit of the preventive measures provided by a program such as the Open Cycle Cooling Water Program." Except for the containment isolation components in the Normal Service Water System (NSW), the components identified in these questions are non-safety related, subjected to raw water from the Harris Lake or Cooling Tower basin and are outside the scope of the Open-Cycle Cooling Water Program. This program is based on GL 89-13 as implemented by HNP's GL 89-13 Program, which only applies to the safety related Emergency Service Water and Emergency Screen Wash Systems and not those non-safety related systems associated with the referenced LRA tables.

Although not officially part of the program, the components that are the subject of these questions are subjected to the preventive measures in the Open-Cycle Cooling Water Program. NUREG-1801, Volume 2, Section XI.M20 describes the preventive measures as:

> The system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments. Implementation of NRC GL 89-13 includes a condition and performance monitoring program; control or preventive measures, such as chemical treatment, whenever the potential for biological fouling species exists; or flushing of infrequently used systems. Treatment with chemicals mitigates microbiologically influenced corrosion (MIC) and buildup of macroscopic biological fouling species, such as blue mussels, oysters, or clams. Periodic flushing of the system removes accumulations of biofouling agents, corrosion products, and silt.

The preventive measures described above primarily include design features, periodic flushing activities and/or chemical treatments. These activities include actions taken to prevent degradation. Condition and Performance Monitoring does not prevent degradation and is not considered a preventive action. Nevertheless, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program represents a collection of condition monitoring activities since it is done in conjunction with ongoing preventive maintenance activities.

LRA Tables:
The following systems are subjected to raw water that is circulated through the cooling tower basin and connected systems:

3.3.2-6 Circulating Water (CW) System; See LRA Subsection 2.3.3.6 for portion supporting Compliance with Fire Protection 10 CFR 50.48.

3.3.2-7 Cooling Tower (CT) System; See LRA Subsection 2.3.3.7 for portion supporting Compliance with Fire Protection 10 CFR 50.48.

3.3.2-10 Normal Service Water (NSW) System; See LRA Subsection 2.3.3.12 for portion supporting Compliance with Fire Protection 10 CFR 50.48, seismic continuity, and spatial interaction.

3.3.2-13 Waste Processing Building Cooling Water System; See LRA Subsection 2.3.3.15 for portion supporting spatial interaction (Non-essential component cooling water heat exchanger water box components are made of carbon steel clad with 90-10 Cu-Ni and Monel brass. These components are supplied by the NSW System connected at its flanges. Also included are small bore piping components (e.g., heat exchanger instrumentation, test connections, vents and drains).

The following systems are subjected to raw water directly from the lake:

3.3.2-8 Cooling Tower Make-Up (CTMU) System; See LRA Subsection 2.3.3.8 for portion supporting Compliance with Fire Protection 10 CFR 50.48.

3.3.2-9 Screen Wash System; See LRA Subsection 2.3.3.9 for portion supporting Compliance with Fire Protection 10 CFR 50.48, seismic continuity, and spatial interaction.

3.3.2-34 Upflow Filter System; See LRA Subsection 2.3.3.38 for portion supporting spatial interaction.

The Open-Cycle Cooling Water Program supporting document describes the use of the cooling tower basin water as a means to chemically treat the NSW, Circulating Water and the safety-related Emergency Service (ESW) systems. Cooling tower water is the water source for the first group of systems above. Consequently they receive the same chemical treatment preventive measures as the safety related portions of the system, which are supplied by the NSW system. The first group of system component materials is similar to the corresponding components in the safety-related ESW system.

Flushing activities for small bore piping in the NSW are performed as need to support normal plant operation. The NSW system intended function required for supporting ESW system loads during shutdown in case of fire are normally in operation and therefore do not require periodic flushing. Flow through small bore piping in the NSW is needed for normal operation and has no bearing on spatial interactions or seismic continuity. Flushing of small bore piping is not required to support the NSW system intended functions.

Per FSAR Section 9.2.1.2, “When operable, the Cooling Tower can provide cooling water for Unit shutdown without reliance on the Main or Auxiliary Reservoirs. During shutdown, the cooling tower evaporative losses are sufficiently low so that makeup to the Cooling Tower will not be required.” Consequently, the CTMU system is not relied upon to supply makeup water during shutdown in case of fire. As noted in LRA Subsection 2.3.3.8, the CTMU System discharge piping forms a pressure boundary with the concrete conduit (pipe) between the CT Basin and the ESW & CT Makeup Intake Structure. No additional preventive measures other than design are needed to support this intended function.

The in-scope portion of the non-safety related Screen Wash System serves Bays 1 and 8 in the Screening Structure. Except for inspections of Intake Bay 1, there are no different preventive measures as compared with those that address the Emergency Service Water Screen Wash System in Bays 6 and 8. The conditions in Screening Structure Bays 6 and 8 are considered representative of the other bays including Bay 1. Because of the higher flow rates in the ESW system, buildup of silt and debris would be worse in Bays 6 and 8 as compared to Bay 1. Findings in Bays 6 and 8 are entered into the corrective action program, which should address any required actions for Bay 1.

The portion of the Upflow Filter system that is subject to AMR is located in the Screening Structure as discussed in LRA Subsection 2.3.3.38. This is an alternate supply of Raw Water to the plant's water treatment facilities and not the normal water supply. This system is included due to the potential for spatial interaction with safety related equipment located in the Screening Structure. Other than design considerations, no additional preventive measures are considered necessary for aging management of this equipment as there are no flow requirements needed to support the license renewal system intended function.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has provided a detailed clarification which adequately explains the basis for not managing these components under the Open-Cycle Cooling Water System Program. For most of these components, the cooling tower basin is the normal water source which is treated with biocide chemicals equivalent to the Open-Cycle Cooling Water System Program. In addition for the systems that take their water directly from the lake, the applicant explained that, although these systems do not receive a biocide treatment, the components in these systems do not support safety-related functions. In addition in these systems, flushing is performed for those that require flow to perform their intended function. This question is resolved.

Question No. 3.3.1-77-MK-01

REQUEST
In LRA Table 3.3.2-02, loss of material for carbon or low alloy steel piping, piping components, and piping elements exposed to raw water is managed by the One-Time Inspection Program. Please explain why this program is more suitable to manage this aging effect than the Open Cycle Cooling Water Program.

RESPONSE
These line items in Table 3.3.2-2 reference plant-specific Notes 369 and 376. These notes state:

> Note 376: "This line item represents components associated with the BTRS Chiller condenser wetted by service water (raw water). These components are non-safety related; and, therefore, cannot be managed using the Open-Cycle Cooling Water Program."
>
> Note 369: "An aging effect is not expected to occur, but the data is insufficient to rule it out with reasonable confidence. Therefore, a one-time inspection will provide assurance the aging mechanism is not occurring."

The assignment of the One-Time Inspection Program is not appropriate. The basis documents and the LRA will be amended to reassign this LRA item (page 3.3-134) from the One-Time Inspection Program to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. Plant-specific Note 369 will be deleted from this line item. Additionally, in the Discussion column for LRA Table line 3.3.1-77, change the last sentence of the second paragraph to read:

> "The aging effect is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program."

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant will amend the LRA to change the aging management program from One-Time Inspection to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. This program will provide for periodic visual inspections of the internal surfaces to detect any age related degradation. On this basis, the staff finds the applicant's response acceptable. This question is resolved.

Question No. 3.3.1-79-MK-01

REQUEST
In the following LRA Tables 3.3.2-06, 3.3.2-09, 3.3.2-10 and 3.3.2-34, Table 1 line item 3.3.1-79 is used to manage loss of material due to crevice and pitting corrosion and flow blockage due to fouling for the following stainless steel component types: piping, piping components, and piping elements; system strainer screens/elements; and, system strainers exposed to raw water with the Inspection of Internal Surfaces in Miscellaneous Piping Program. Please explain the basis for adequately managing these aging effects without the benefit of the preventive measures provided by a program such as the Open Cycle Cooling Water Program.

RESPONSE
Questions 3.3.1-76-MK-01, 3.3.1-79-MK-01, 3.3.1-80-MK-01, and 3.3.1-81-MK-01 have a common theme. See the response to Question 3.3.1-76-MK-01.

STAFF EVALUATION
Refer to the staff evaluation for Question 3.3.1-76-MK-01

Question No. 3.3.1-80-MK-01

REQUEST
In the following LRA Tables 3.3.2-06, 3.3.2-09, 3.3.2-10 and 3.3.2-34, Table 1 line item 3.3.1-80 is used to manage loss of material due to microbiologically influenced corrosion (MIC) for the following stainless steel component types: piping, piping components, and piping elements; system strainer screens/elements; and, system strainers exposed to raw water with the Inspection of Internal Surfaces in Miscellaneous Piping Program. Please explain the basis for adequately managing these aging effects without the benefit of the preventive measures provided by a program such as the Open Cycle Cooling Water Program.

RESPONSE
Questions 3.3.1-76-MK-01, 3.3.1-79-MK-01, 3.3.1-80-MK-01, and 3.3.1-81-MK-01 have a common theme. See the response to Question 3.3.1-76-MK-01.

STAFF EVALUATION
Refer to the staff evaluation for Question 3.3.1-76-MK-01

Question No. 3.3.1-81-MK-01

REQUEST
In the following LRA Tables 3.3.2-09, 3.3.2-13 and 3.3.2-34, Table 1 line item 3.3.1-80 is used to manage loss of material due to crevice, MIC and pitting corrosion as well as flow blockage due to fouling for the following copper alloy component types: piping, piping components, and piping elements; and, system strainer screens/elements exposed to raw water with the Inspection of Internal Surfaces in Miscellaneous Piping Program. Please explain the basis for adequately managing these aging effects without the benefit of the preventive measures provided by a program such as the Open Cycle Cooling Water Program.

RESPONSE
Questions 3.3.1-76-MK-01, 3.3.1-79-MK-01, 3.3.1-80-MK-01, and 3.3.1-81-MK-01 have a common theme. See the response to Question 3.3.1-76-MK-01.

STAFF EVALUATION
Refer to the staff evaluation for Question 3.3.1-76-MK-01

Question No. 3.3.1-89-MK-01

REQUEST
In LRA Table 3.1.2-4, this Table 1 item is being used to manage the loss of material due to boric acid corrosion for the carbon or low alloy RCP lube oil collection tank component type. Please confirm that a Note A was intended as opposed to a Note C for a different component type.

RESPONSE
You are correct; Note A was intended in all cases in Table 3.1.2-4 where this line item is referenced. Line item 3.3.1-89 refers to component groups “Steel bolting and external surfaces exposed to air with borated water leakage.”

In the context of the Boric Acid Corrosion Program, the external surfaces of any component are treated the same way. This is supported by NUREG-1801, XI.M10. It states under Scope of the program, “The program covers any structures or components on which boric acid corrosion may occur (e.g., steel and aluminum), and electrical components on which borated reactor water may leak.” There are no adverse impacts of assigning Notes A or C to this line item as all susceptible components are treated equally. In this case, HNP believes there is no value in amending the LRA and supporting documentation solely for the purposes of providing a consistent Standard Note.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has adequately clarified the application of Note C. The staff concurs that the assignment of Note C over Note A does not affect the management of or the AMPs that are credited to managing this aging effect. So the LRA does not need to be amended. This question is resolved.

Question No. 3.3.1-89-MK-02

REQUEST
In LRA Table 3.3.2-14, this Table 1 item is being used to manage the loss of material due to boric acid corrosion for carbon or low alloy piping, piping components, piping elements, and tanks component type exposed to treated water (inside). Please justify the use of this Table 1 item to manage this aging effect for this component type exposed to this environment.

RESPONSE
There is a mistake in LRA Table 3.3.2-14 on page 3.3-201. Under Piping, Piping components, Piping elements, and tanks, M-1, Carbon or Low Alloy Steel, the Environment for line items 3.3.1-59 and 3.3.1-89 should read Air - Indoor (outside). The LRA will be amended to make this correction.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant will amend the LRA to change the environment for Table 3.3.1, items 3.3.1-59 and 3.3.1-89 from treated water to air-indoor (outside). This question is resolved.

Question No. 3.3.1-90-MK-01

REQUEST
On page 3.3-352 of the LRA, cracking due to stress corrosion cracking for stainless steel piping, piping components, and piping elements exposed to treated water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. Please explain the basis for adequately managing this aging effect without the benefit of the preventive measures provided by a program such as the Open Cycle Cooling Water Program.

RESPONSE
This line has been deleted. The supporting document has been revised and cracking due to stress corrosion cracking is no longer considered applicable. This conclusion was reached since the fluid temperature is not expected to exceed the temperature threshold for this mechanism.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant will amend the LRA to delete this result item since the applicant has concluded that cracking due to stress corrosion cracking is no longer considered applicable. The staff finds this response acceptable because the system temperature does not exceed the threshold for this aging mechanism. This question is resolved.

Question No. 3.3.1-91-MK-01

REQUEST
On page 3.3-352 of the LRA, loss of material due to crevice and pitting corrosion for stainless steel piping, piping components, and piping elements exposed to treated water is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. Please explain the basis for adequately managing this aging effect without the benefit of the preventive measures provided by a program such as the Open Cycle Cooling Water Program.

RESPONSE
The Spent Resin Storage and Transfer System is a nonsafety-related system and its internal environment is subjected to a treated water environment. This system is not a cooling water system nor associated with one. Therefore, this system should not be subjected to the requirements of GL 89-13.

In NUREG-1801, Section XI.M38, Internal Surfaces in Miscellaneous Piping and Ducting Components Program, describes this system as:

> The program consists of inspections of the internal surfaces of steel piping, piping components, ducting, and other components that are not covered by other aging management programs. These internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. The program includes visual inspections to assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions.

There are no preventive measures required by this program and none are required to manage this equipment. Because this system is intermittently used, HNP considers it appropriate to use a condition monitoring program based on maintenance activities for managing the aging effect of loss of material. As noted in NUREG-1801, XI.M38, under Scope of the Program, loss of material can be identified by visual techniques and is therefore appropriate for this program. For the foregoing reasons, the selection of the Internal Surfaces in Miscellaneous Piping and Ducting Components Program is appropriate.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant clarified that, although this system is not safety-related nor subject to the requirements of GL 89-13, the internal environment is treated water which provides preventive benefits equivalent to the Open Cycle Cooling Water System Program. In addition, the program used to manage loss of material for these result items is capable of detecting this aging effect through periodic visual inspections. This question is resolved.

Question No. 3.3.1-98-MK-01

REQUEST
On page 3.3-364, -377, and -383, copper alloy >15% Zn piping, piping components, and piping elements exposed to air/gas (Wetted) (Inside) references Table 1 item 3.3.1-98. Please explain the basis for assigning this Table 1 item which is for piping, piping components, and piping elements exposed to dried air and not a wetted environment.

RESPONSE
On page 3.3-364, -377, and -383, copper alloy >15% Zn piping, piping components, and piping elements exposed to air/gas (Wetted) (Inside) are assigned plant-specific Note 394. This note states as follows:

> 394. This environment represents indoor air for systems with temperatures higher than the dew point, i.e., condensation can occur but only rarely, equipment surfaces are normally dry.

The subject LRA component commodity refers to the inside surface of brass ventilation instrumentation valves, that are expected to be normally dry.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant clarified that the component being managed in this AMR result item refers to the inside surface of ventilation instrumentation valves which are normally dry. On this basis the staff finds the applicant’s response acceptable. This question is resolved.

Question No. 3.3.2-01-MK-01

REQUEST
On page 3.3-120, the loss of material due to galvanic corrosion in carbon steel CSIP lube oil piping components is managed by the Lubricating Oil Analysis Program and the One Time Inspection Program with a Note H. How do these programs manage this AE for this material and environment?

RESPONSE
As noted in LRA Section B.2.25,

> The Lubricating Oil Analysis Program maintains oil system contaminants (primarily water and particulates) within acceptable limits, thereby preserving an environment that is not conducive to loss of material, cracking, or reduction of heat transfer. Lubricating oil testing activities include sampling and analysis of lubricating oil for detrimental contaminants.

The HNP basis document that addresses aging mechanism in for dissimilar metals in Lubricating Oil indicates that lubricating oil does not produce any potential aging effects unless there is water contamination and pooling in contact with these dissimilar metals. As noted above, the Lubricating Oil Analysis Program monitors the quality of the oil and identifies the presence of moisture in its samples thereby ensuring the environment is not conducive to galvanic corrosion. The results of the One Time Inspection Program for these components will confirm the acceptability of this approach throughout the period of extended operation.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant clarified that for this aging mechanism to occur there must be water contamination and pooling in contact with these dissimilar metals and has credited the Lubricating Oil Analysis Program to verify that water or moisture impurities are not present in the lubricating oil, and which otherwise (if present) could lead to an environment conducive to galvanic corrosion. More importantly, the staff has verified that the applicant’s AMR in LRA Table 3.3.2-1 for carbon steel CSIP lube oil piping exposed to lubricating oil also credits the One-Time Inspection Program and that this AMP is credited to verify that the Lubricating Oil Analysis Program is achieving its function of precluding water or moisture impurities in the lubricating oil and that loss of material has not occurred in the surfaces of these piping components. This question is resolved.

Question No. 3.3.2-01-MK-02

REQUEST
On page 3.3-129, the change in material properties due to various degradation mechanisms for elastomers exposed to treated water and air-indoor (Outside) is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. How does this program detect this aging effect through visual inspections?

RESPONSE
This item is the elastomer diaphragm in the Boric Acid Tank. Inspections of elastomeric components will include physical manipulation to detect aging effects, in addition to visual inspection.

LRA Section B.2.24 will be revised by adding:

> Inspections of elastomeric components will include physical manipulation to detect aging effects, in addition to visual inspection.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant will amend the LRA to add physical manipulation to the inspection of elastomer components under the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program in addition to visual. This question is resolved.

Question No. 3.3.2-02-MK-01

REQUEST
On page 3.3-133, loss of material due to galvanic corrosion for carbon or low alloy steel piping, piping components, and piping elements exposed to lubricating oil or hydraulic fluid is managed by Lubricating Oil Analysis and One-Time Inspection Programs. How does the Lubricating Oil Analysis Program provide preventive measures for this aging effect?

RESPONSE
See Response to Question 3.3.2-01-MK-01.

STAFF EVALUATION
Refer to the staff evaluation for Question 3.3.2-01-MK-01

Question No. 3.3.2-04-MK-01

REQUEST
On page 3.3-145, the reduction of heat transfer effectiveness due to fouling of heat transfer surfaces for stainless steel primary sampling cooler tubes exposed to treated water (Inside) is managed by the Water Chemistry Program. How is the effectiveness of the Water Chemistry Program in managing this aging effect verified for this component type?

RESPONSE
The treated water on the inside of the tubes is primary water, which is maintained at a very high quality by the Water Chemistry Program. The external surfaces of the tubes are managed by the Closed Cycle Cooling Water Program, which includes verification of the heat transfer surfaces. See the response to question B.2.11-MK-01.

STAFF EVALUATION
The question is relevant only to the management of fouling on M-5 heat transfer function for these tubes. The applicant's Water Chemsitry Program as applied to the primary coolant passing through the interior of these tubes is borated and controlled with additives which maintains the quality of the primary coolant at level that should preclude the occurrence of corrosion products, that if otherwise present, could cause fouling and potentially lead to a loss of heat transfer capability. The staff finds the applicant's response acceptable because the applicant clarified how the Water Chemistry Program will be used to managing fouling in the interior surfaces of the sampling cooler tubes and how the Closed Cycle Cooling Water Program will be used to managing fouling on the external surfaces of the tubes, which includes verification of the cleanliness of the heat transfer surfaces. This question is resolved.

Question No. 3.3.2-09-MK-01

REQUEST
On page 3.3-160, the loss of material due to selective leaching for gray cast iron Fire Service Screen Wash Pumps exposed to raw water is managed by the Selective Leaching of Materials Program. These items have a Note B. Please confirm that a Note D was intended because this is a different component type.

RESPONSE
The Suction Bell and Casing of the Fire Service Screen Wash Pumps are gray cast iron. HNP methodology treats these items as piping components. Therefore, Note B is appropriate.

The above conclusion is consistent with the definition of Piping, piping components, and piping elements as described in Volume 2 of NUREG-1801, Table IX.B, Selected Definitions & Use of Terms for Describing and Standardizing Structures and Components:

> This general category includes various features of the piping system that are within the scope of license renewal. Examples include piping, fittings, tubing, flow elements/indicators, demineralizer, nozzles, orifices, flex hoses, pump casing and bowl, safe ends, sight glasses, spray head, strainers, thermowells, and valve body and bonnet. For reactor coolant pressure boundary components in Chapter IV that are subject to cumulative fatigue damage, this can also include flanges, nozzles and safe ends, penetrations, vessel head, shell, welds, stub tubes and miscellaneous Class 1 components, such as pressure housings.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant clarified that the pumps are included in the component type piping, piping components, and piping elements so the assignment of Note B is appropriate. This question is resolved.

Question No. 3.3.2-19-MK-01

REQUEST
On page 3.3-230, carbon steel piping, piping components, and piping elements exposed to lubricating oil or hydraulic fluid (Inside) does not have an aging effect requiring management. Explain what specific carbon steel component does not have an aging effect requiring management in this environment.

RESPONSE
This item in LRA Table 3.3.2-19 refers to plant-specific note 729. Note 729 states on page 3.3-448:

> This line represents an immersion heater whose configuration in the tank is such it would not credibly come in contact with water in the event of contamination or pooling. The HNP methodology predicts no aging affects in lubricating oil without water contamination.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant clarified that the component being managed represents an immersion heater whose configuration would not allow the component to come into contact with water. This question is resolved.

Question No. 3.3.2-19-MK-02

REQUEST
On page 3.3-228, cracking due to SCC for stainless steel flow restricting elements exposed to lubricating oil or hydraulic fluid (inside) is being managed by the Lubricating Oil Analysis and One-Time Inspection Programs. What measures in these programs provide prevention for this aging effect?

RESPONSE
Note 397 states that water contamination is assumed as the basis for predicting the potential aging effect. Cracking due to SCC for stainless steel flow restricting elements exposed to lubricating oil or hydraulic fluid is managed by ensuring the amount of water content is within acceptable levels. See the response to question 3.3.2-01-MK-01

STAFF EVALUATION
The staff verified that, in the stated AMR on page 3.3-228, the applicant credits both the Lubricating Oil Analysis Program and the One-Time Inspection Program to manage cracking due to SCC in the surfaces of these stainless steel flow restrictors that are exposed to a lubricating oil environment. Refer to the staff's evaluation of the applicant's response to Question 3.3.2-01-MK-01.

Question No. 3.3.2-22-MK-01

REQUEST
On page 3.3-252, change in material properties and cracking due to various degradation mechanisms for elastomer piping, piping components and piping elements exposed to fuel oil (inside) are managed by External Surfaces Monitoring. Please explain how this program can manage these aging effects before the loss of intended function. Also please explain why this same item has no aging effect listed for this material and environment combination.

RESPONSE
The elastomer hoses are fuel oil manifold lines that run along and in close proximity to the Security Power System diesel engine. LRA Note 353 describes the rationale for why the elastomer piping, piping components and piping elements have the listed aging effects and why visual observation of the exterior surface is indicative of the internal surface. The note is applicable whether or not the fluid temperature on the inside of the hose is higher than the surrounding air. In this case it is envisioned that the fuel oil hose would be heated by the air surrounding the engine components. Consequently, the aging effects would likely appear on the outside surface before they would on the inside.

Note 353: The aging effects for elastomer hoses are driven by temperature (T>95°F) and not the chemistry of the fluid medium. This is a standby system and temperature is usually maintained above 95°F by the keep warm subsystems. Since the external heat transfer mechanism is natural convection and minimal, it is reasonable to conclude that the aging effects on the external surface are representative of those on the internal surface. Consequently, aging management can be done by external examination.

For the line items with no aging effects, LRA Note 702 identifies the component and its environment.

Note 702: This AMR line represents fuel oil hoses connecting sections of the fuel oil supply and return line that transfers oil between the buried, main storage tank and the fuel oil day tank. They are connected to the tank and protected by an access cover on the concrete slab above the storage tank. The environment selected to represent this area is a cool, damp air space. Cool temperatures (< 95°F) in this air space ensure no aging effects for the hoses.

STAFF EVALUATION
The staff's question has been closed to Open Item 3.4-1, Parts 1, 2, 3, and 4 on aging management of elastomeric and thermoplastic materials.

Question No. 3.3.2-27-MK-01

REQUEST
On page 3.3-287, for copper alloy >15% zinc spray nozzles, fouling is not considered as an AE than required to be managed for the spray pattern intended function. Please confirm that this is intended and then justify excluding this AE for this intended function.

RESPONSE
Yes, this is intended. See Response to Question 3.3.1-70-MK-01.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant clarified that this is the same as the question which was asked as question 3.3.1-70-MK-01. Refer to question 3.3.1-70-MK-01 for the staff evaluation. This question is resolved.

Question No. 3.3.2-27-MK-02

REQUEST
On page 3.3-288, for copper alloy >15% zinc sprinklers, fouling is not considered as an AE than required to be managed for the spray pattern intended function. Please confirm that this is intended and then justify excluding this AE for this intended function.

RESPONSE
Yes, this is intended. See Response to Question 3.3.1-70-MK-01.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant clarified that this is the same as the question which was asked as question 3.3.1-70-MK-01. Refer to question 3.3.1-70-MK-01 for the staff evaluation. This question is resolved.

Question No. 3.3.2-46-MK-01

REQUEST
On page 3.3-347, reduction of heat transfer effectiveness due to fouling of heat transfer surfaces for stainless steel fuel pools heat exchanger tubes exposed to treated water (Inside) is managed by the Water Chemistry Program. How does a chemistry only program adequately manage this aging effect? How is the effectiveness of this program verified?

RESPONSE
The treated water on the inside of the tubes is spent fuel pool water, which is maintained at a very high quality by the Water Chemistry Program. The external surfaces of the tubes are managed by the Closed Cycle Cooling Water Program, which includes verification of the heat transfer surfaces. See the response to question B.2.11-MK-01.

STAFF EVALUATION
The question is relevant only to the management of fouling on M-5 heat transfer function for these tubes. The applicant's Water Chemsitry Program as applied to the primary coolant passing through the interior of these tubes is borated and controlled with additives which maintains the quality of the primary coolant at level that should preclude the occurrence of corrosion products, that if otherwise present, could cause fouling and potentially lead to a loss of heat transfer capability. The staff finds the applicant's response acceptable because the applicant clarified how the Water Chemistry Program will be used to managing fouling in the interior surfaces of the sampling cooler tubes and how the Closed Cycle Cooling Water Program will be used to managing fouling on the external surfaces of the tubes, which includes verification of the cleanliness of the heat transfer surfaces. This question is resolved.

Question No. 3.3.2-70-MK-01

REQUEST
On page 3.3-340, the loss of material due to crevice and pitting corrosion for stainless steel remote sample dilution panel sample cooler tubes exposed to treated water (Outside) is managed using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program. Please explain how this program will manage these aging effects on the external surfaces of the tubes.

RESPONSE
Correction, LRA page 3.3-430 shows this item.

Note 382 referring to the treated water side states:

> This environment represents the chilled water loop from the Remote Sample Dilution Panel Refrigeration Unit to the Remote Sample Dilution Panel Sample Cooler.

The remote sample dilution panel sample cooler tubes are located inside the cooler, which contains the treated water. The cooler must be disassembled in order to inspect the outside of the tubes.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant clarified that the remote sample dilution panel sample cooler tubes are located inside the cooler. The cooler which contains treated water must be opened up to inspect the tubes so the treated water which is contained in the cooler is the external environment for the tubes. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program will provided for visual inspections inside of the cooler. This question is resolved.

Question No. 3.4.2-6-SA-01

REQUEST
Table 3.4.2-6, page 3.4-53, applicant takes credit for GALL Report items VIII.I-15 and VIII.H-7 for aging management of elastomers. GALL Report items VIII.I-15 and VIII.H-7 are applicable to steel material only. Justify crediting these GALL Report items for elastomers.

RESPONSE
NEI 95-10 Revision 6, page 33 states, "Each combination of component type, material, environment and aging effect requiring management should be compared with NUREG-1801 Volume 2 line items to identify consistencies. If there is no corresponding line item in NUREG-1801 Volume 2, the combination is a plant-specific aging evaluation result."

Based on the above, HNP is not taking credit for GALL Report items VIII.I-15 and VIII.H-7 for aging management of elastomers, since NUREG-1801, Revision 1, Section VIII.D1 Feedwater System (PWR) and Section VII.D Compressed Air System do not contain elastomer material.

LRA Table 3.4.2-6, page 3.4-53 contains a line item for piping components constructed of elastomer in a dry air/gas environment with no aging effects and no aging management program required. NUREG-1801 Volume 2 Item VIII.I-15 was referenced in LRA Table 3.4.2-6, page 3.4-53 because the component, environment, aging effect/mechanism and aging management program was the same as GALL Report item VIII.I-15.

LRA Table 3.4.2-6, page 3.4-53 contains a line item for piping components constructed of elastomer in an indoor air environment with aging effects of cracking due to various degradation mechanisms and change in material properties due to various degradation mechanisms managed by the External Surfaces Monitoring program. NUREG-1801 Volume 2 Item VIII.H-7 was referenced in LRA Table 3.4.2-6, page 3.4-53 because the components' external surface was the same, the indoor air environment was the same, aging effects were attributed although not identical, and the aging management program was the same as GALL Report item VIII.I-15.

In summary, since there is no corresponding line item in NUREG-1801 Volume 2, the referenced GALL Report line items were selected.

STAFF EVALUATION
This question has been closed to Open Item 3.4-1, Parts 1, 2, 3, and 4 on aging management of elastomeric and thermoplastic materials.

Question No. 3.4.2-8-SA-01

REQUEST
Section 3.4.1.1, page 3.4-2, applicant states that plant-specific OE review identified instances of general corrosion of carbon steel piping normally operating at temperatures above 212 °F in Auxiliary Steam Condensate System and this has been addressed in the AMR of this system. Table 3.4.2-8 for Auxiliary Steam Condensate System does not address any environment with temperatures above 212 °F. Clarify this discrepancy and provide specific examples of OE for Auxiliary Steam Condensate System.

RESPONSE
LRA Table 3.4.2-8 for Auxiliary Steam Condensate, page 3.4-63 identifies Piping, piping components, and piping elements made of carbon or low alloy steel in an Air - Indoor environment with aging effects of loss of material due to general corrosion and managed by the External Surfaces Monitoring AMP. This line item references plant-specific Note 418. On page 3.4-77 this note states: Although these carbon steel lines are normally above 212°F, plant-specific operating experience has indicated there have been incidences where external corrosion has been found.

As part of the operating experience review performed, system engineers were interviewed as to the condition of each system. The system engineer for the Auxiliary Steam Condensate System reported that plant personnel have identified locations on the external surface of carbon steel piping operating above 212 °F where corrosion has been found.

AR 154890 - A thru wall pipe leak was found on a drain line in the Water Treatment Building. This through wall condition was the result of external corrosion. This degraded Auxiliary Condensate pipeline is insulated. It appears that water or condensation has gotten underneath the metallic insulation and over time corroded through the pipe wall. This condition has been periodically found on some pipelines that are not in continuous operation. A work order has been created to replace this pipe. Although this OE is for a portion of the system not in the scope of License Renewal, it is considered representative of conditions for the in-scope portion.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant credited External Surfaces Monitoring Program for aging management of loss of material due to general corrosion of steel piping exposed to an environment of air above 212 °F. Therefore, the staff concludes that implementation of this program provides a high level of assurance that the component's intended function will be maintained within CLB for the extended period of operation.

Question No. 3.4.2-12-SA-01

QUESTION:
Provide basis for crediting One-Time Inspection Program for management of aging effects (loss of material due to crevice corrosion, pitting corrosion, and cracking due to SCC of stainless steel piping, piping components, and piping elements exposed to treated water (inside) environment in steam generator wet lay up system (Table 3.4.2-12, page 3.4-74).

RESPONSE:
The Steam Generator Wet Lay Up System is used only to maintain chemistry conditions during wet lay up of the Steam Generators. This will reduce Steam Generator corrosion during inactive periods.

The LRA Table 3.4.2-12, page 3.4-74 line item piping, piping components, and piping elements exposed to treated water (inside) represents stainless steel piping components that were originally filled with treated water.

The LRA will be amended to identify that this line item (Table 3.4.2-12, page 3.4-74; and the list of aging management programs shown in Section 3.4.2.1.12) will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

Also, plant-specific Note 414 will be amended to state the Item represents piping components that are water-filled but not used on a regular basis. The water source is from treated water.

A License Renewal Application amendment is required.

NRC Staff Evaluation:
The staff finds the applicant's response acceptable because the applicant has agreed to amend the LRA to credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program instead of One-Time Inspection Program to manage the aging effects. The applicant will also revise plant-specific Note 414 to indicate that the item represents piping components that are water-filled and are not used on a regular basis. Since the line is not used on a regular basis, the staff concludes that implementation of this program provides a high level of assurance that the components intended function will be maintained within CLB for the extended period of operation.

Question No. 3.4.2-12-SA-02

REQUEST
Provide basis for crediting One-Time Inspection Program for management of aging effects (loss of material due to crevice corrosion, general corrosion, microbiologically influenced corrosion, and pitting corrosion) of carbon or low alloy steel piping, piping components, and piping elements exposed to raw water (inside) environment in steam generator wet lay up system (Table 3.4.2-12, page 3.4-73).

RESPONSE
The Steam Generator Wet Lay Up System is used only to maintain chemistry conditions during wet lay up of the Steam Generators. This will reduce Steam Generator corrosion during inactive periods.

The LRA Table 3.4.2-12, page 3.4-73 line item piping, piping components, and piping elements exposed to raw water (inside) represents a sample cooler with cooling water supplied from the service water system.

The LRA will be amended to identify that this line item (Table 3.4.2-12, page 3.4-73; and the list of aging management programs shown in Section 3.4.2.1.12) will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

Plant-specific Note 412 will be amended to state the Commodity and environment represent a sample cooler with cooling water supplied with service water. The item represents piping components that are water-filled but not used on a regular basis.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has agreed to amend the LRA to credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program instead of One-Time Inspection Program to manage the aging effects. The applicant will also revise Note 412 to indicate that the item represents a sample cooler with cooling water supplied with service water. The item represents piping components that are water-filled and are not used on a regular basis. Since the line is not used on a regular basis, the staff concludes that implementation of this program provides a high level of assurance that the components intended function will be maintained within CLB for the extended period of operation.

Question No. 3.4.2-12-SA-03

REQUEST
Table 3.4.2-12, page 3.4-73: Provide basis for crediting One-Time Inspection Program for management of aging effects (crevice, general, and pitting corrosion) of carbon or low alloy steel piping, piping components, and piping elements exposed to treated water (inside) environment in steam generator wet lay up system.

RESPONSE
The Steam Generator Wet Lay Up System is used only to maintain chemistry conditions during wet lay up of the Steam Generators. This will reduce Steam Generator corrosion during inactive periods.

The LRA Table 3.4.2-12, page 3.4-73 line item piping, piping components, and piping elements exposed to treated water (inside) represents carbon steel piping components that were originally filled with treated water.

The LRA will be amended to identify that this line item (Table 3.4.2-12, page 3.4-73; and the list of aging management programs shown in Section 3.4.2.1.12) will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

Also, plant-specific Note 414 will be amended to state the Item represents piping components that are water-filled but not used on a regular basis. The water source is from treated water.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has agreed to amend the LRA to credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program instead of One-Time Inspection Program to manage the aging effects. The applicant will also revise Note 414 to indicate that the item represents piping components that are water-filled and are not used on a regular basis. The water source is from treated water. Since the line is not used on a regular basis, the staff concludes that implementation of this program provides a high level of assurance that the components intended function will be maintained within CLB for the extended period of operation.

Question No. 3.4.2-2-SA-01

REQUEST
Provide basis for crediting One-Time Inspection Program for management of aging effects (loss of material due to crevice corrosion, general corrosion, and pitting corrosion) of carbon or low alloy steel piping, piping components, and piping elements exposed to treated water (inside) environment in steam generator chemical addition system (Table 3.4.2-2, page 3.4-38).

RESPONSE
Using the Steam Generator Chemical Addition System, ammonia and hydrazine were formerly injected by valves supplying the Steam Generators through the Main Feedwater and Auxiliary Feedwater Systems. These valves have been locked closed as chemical requirements for the new Steam Generators have changed.

The LRA Table 3.4.2-2, page 3.4-38 line item piping, piping components, and piping elements exposed to treated water (inside) represents carbon steel piping components that were originally filled with treated water.

The LRA will be amended to identify that this line item (Table 3.4.2-2, page 3.4-38; and the list of aging management programs shown in Section 3.4.2.1.2) will be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

Also, plant-specific Note 413 will be amended to state the Item represents piping components that are water-filled but not used on a regular basis. The water source is from treated water.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has agreed to amend the LRA to credit the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program instead of One-Time Inspection Program to manage the aging effects. The applicant will also revise plant-specific Note 413 to indicate that the item represents piping components that are water-filled and are not used on a regular basis. The water source is from treated water. Since the line is not used on a regular basis, the staff concludes that implementation of this program provides a high level of assurance that the components intended function will be maintained within CLB for the extended period of operation.

Question No. 3.4.2-3-SA-01

REQUEST
For items on pages 3.4-41, 3.4-43, and 3.4-45 where components are exposed to hydraulic fluid (inside), applicant takes credit for Lubricating Oil Analysis Program and One-Time Inspection Program to manage loss of material due to crevice, general, and pitting corrosion. Provide difference in properties between lubricating oil and hydraulic fluid and basis for selecting Lubricating Oil Analysis Program.

RESPONSE
The Main Steam Power Operated Relief Valve (PORV) operators use a triaryl phosphate hydraulic fluid. Water contamination is indicated by operating experience.

Lubricating oils are low to medium viscosity hydrocarbons, with possibility of water contamination, used for bearing, gear, and engine lubrication. Piping, piping components, and piping elements (whether copper, stainless steel, or steel) when exposed to lubricating oil that does not have water pooling will not be subject to aging degradation because there are no relevant aging mechanisms. Water contamination is assumed for the HNP lubricating oils.

The basis for selecting the Lubricating Oil Analysis Program follows:

1) At HNP, the analyses of hydraulic fluids and lubricating oils are performed using similar predictive maintenance processes and procedures.

2) The same HNP engineering personnel review analyses of hydraulic fluid and lubricating oils, respond to the findings, and when necessary take the appropriate actions. Equipment assessments created in the plant database "Plantview" between 2002 and 2006 were reviewed for those items relevant to lubricating oil contamination events and/or contamination or changes in lubricating oil properties. The review found results of analyses and recommendations for both lubricating oils and hydraulic fluid.

These items form the basis for selecting the Lubricating Oil Analysis Program to manage the PORV operators' hydraulic fluid environment.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the analysis of hydraulic fluid and lubricating oil is performed using similar processes and procedures for detection of water and particulates contamination. Since Lubricating Oil Analysis Program maintains water and particulates contaminants within acceptable limits, the staff concludes that implementation of this program provides a high level of assurance that the components intended function will be maintained within CLB for the extended period of operation. The applicant’s implementation of the One-Time Inspection Program relative to these components will provide reasonable assurance the Lubricating Oil Analysis Program is achieving its mitgative function and that loss of material due to general, pitting, and crevice corrosion is not occurring the components surfaces that are exposed to either a hydraulic fluid or lubricating oil environment. This question is resolved.

Question No. 3.4.2-3-SA-02

REQUEST
Provide basis for including piping insulation as component requiring aging management in Table 3.4.2-3, page 3.4-40.

RESPONSE
The piping insulation commodity identified on page 3.4-40 includes insulation associated with Main Steam Isolation Valve (MSIV) solenoid valves in the main steam tunnel of the Reactor Auxiliary building (RAB). Please see plant-specific Note 409. The FSAR states that the ASCO solenoid valves associated with the MSIVs require insulation to reduce the maximum surface temperature to remain below the solenoid valve qualification temperature.

In addition, a review of Engineered Safety features safety related air handling units in the RAB and their associated HVAC calculations was performed. The review concluded that Main Steam System piping located in the RAB could contribute to Post-LOCA heat load and therefore a thermal insulation commodity should be added to the Main Steam System.

Based upon this, an insulation commodity was added to the Main Steam System as shown in Table 3.4.2-3, page 3.4-40.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the insulation was included in the design basis for main steam isolation valves requiring insulation to reduce the maximum surface temperature to remain below the solenoid valves qualification temperature. Applicant correctly identified no aging effect requiring management for piping insulation exposed to air-indoor (outside) since air does not have an aging effect on insulation cover which is normally steel or aluminum. GALL Report does not address thermal insulation exposed to air as a component or material that requires aging management during the extended period of operation.

Question No. 3.4.2-3-SA-03

REQUEST
Table 3.4.2-3 and 3.4.2-6: Applicant states that Elastomers, PVC or Thermoplastics material not found in GALL Report for these components (Notes F and J). Provide (a) properties of the specific materials for these components, (b) the basis for concluding that no other aging effects occur in these environments, (c) specific tests and inspection methods for these components including the frequency of inspections, and (d) acceptance criteria and their bases for determining loss of strength of the elastomers, PVC, and thermoplastics.

RESPONSE
The referenced elastomers, PVC or thermoplastics materials detailed in Tables 3.4.2-3 and 3.4.2-6 are not found in Chapter VIII of the GALL Report. Requested information follows:

LRA Table 3.4.2-3 Elastomers

(a) LRA Table 3.4.2-3 identifies elastomer components which include synthetic rubber hydraulic fluid hoses associated with the Power Operated Relief Valve (PORV) actuators.

(b) The HNP basis calculation "Material/Environment Aging Effect Tools For License Renewal" (HNP Tools calculation) identified the aging effects for elastomers as change in material properties due to various degradation mechanisms and cracking due to various degradation mechanisms. These aging effects for elastomers in hydraulic fluid are consistent with industry practice as detailed in Aging Effects for Structures and Structural Components (EPRI Structural Tools). HNP plant-specific OE did not identify any new or unique aging effects. The HNP Tools calculation predicts wear for elastomers if there is relative motion between surfaces not associated with a design deficiency. No operating experience was discovered to indicate that relative motion between surfaces had occurred, and so, wear was not predicted. Based on the above, no other aging effects were predicted.

(c)(1) The external surface of the subject components will be managed by the External Surfaces Monitoring AMP using visual observations during periodic system walkdowns. A quarterly system walkdown frequency is typically established, with all components of the system observed at least once per operating cycle.

(c)(2) No age-related degradation of PORV elastomer components was found during the system operating experience review and as also stated by the Lubricating Oil Analysis program manager at HNP. The internal surfaces will be managed by the One Time Inspection AMP, which is applicable for situations in which additional confirmation is appropriate because an aging effect is not expected to occur but the data is insufficient to rule it out with reasonable confidence. For these cases, there is to be confirmation that either the aging effect is indeed not occurring, or the aging effect is occurring very slowly so as not to affect the component or structure intended function during the period of extended operation.

(d) For the elastomers in a hydraulic fluid environment, testing acceptance criteria will be determined prior to the period of extended operation. Acceptance criteria for elastomeric components may include physical manipulation to detect aging effects, in addition to visual inspection. EPRI's Aging Assessment Field Guide and Expansion Joint Maintenance Guide provide further discussion of elastomeric material inspection techniques.

LRA Table 3.4.2-3 PVC or Thermoplastics

(a) LRA Table 3.4.2-3 identifies PVC or Thermoplastic components which include a plastic breather cap for the hydraulic fluid system associated with the PORV actuators.

(b) The HNP Tools calculation determined that the acceptability for use of thermoplastics within a hydraulic fluid environment is a design driven criteria and once the appropriate material has been selected, there should be no applicable aging effects caused by the working fluid. Also, the HNP Tools calculation states that vinyls are generally unaffected by continuous water exposure and that it is basically inert to almost all inorganic substances (e.g., acids, alkalies, and salts), as well as to water, oil grease, alcohols, and similar materials. Thus, no aging effects were predicted.

© The external surface of the plastic breather cap will be managed by the External Surfaces Monitoring AMP using visual observations during periodic system walkdowns. A quarterly system walkdown frequency is typically established, with all components of the system observed at least once per operating cycle.

(d)(1) Since there were no internal surface aging effects, the application of internal surface acceptance criteria is not applicable.

(d)(2) For the external surface of the plastic breather cap, acceptance criteria will be determined prior to the period of extended operation. Acceptance may be based upon negligible visual degradation or manufacturer's recommendations, as appropriate.

LRA 3.4.2-6 Elastomers

(a) LRA Table 3.4.2-6 identifies elastomer components which represent rubber instrument air hoses associated with valve operators in the Turbine Building.

(b) The air hose internal surfaces are in contact with dry instrument air. Per NEI 95-10, Revision 6, Appendix F, Section 5.2.2.1, internal surfaces subject to dry instrument air should not be subject to aging effects/mechanisms. Thus, no aging effects were predicted.

(c) The external surface of the air hoses will be managed by the External Surfaces Monitoring AMP using visual observations during periodic system walkdowns. A quarterly system walkdown frequency is typically established, with all components of the system observed at least once per operating cycle.

(d)(1) Since there were no internal surface aging effects, the application of internal surface acceptance criteria is not applicable.

(d)(2) For the external surface of the air hoses, testing acceptance criteria will be determined prior to the period of extended operation. Acceptance criteria for elastomeric components may include physical manipulation to detect aging effects, in addition to visual inspection. EPRI's Aging Assessment Field Guide and Expansion Joint Maintenance Guide provide further discussion of elastomeric material inspection techniques.

STAFF EVALUATION
The question has been closed to Open Item 3.4-1, Parts 1, 2, 3, and 4 on aging management of elastomeric and themoplastic components.

Question No. 3.5.1-06-JW-01

REQUEST
LRA Table 3.5.1, Item 3.5.1-06, refers to LRA Subsection 3.5.2.2.1.4 in the discussion column. In Subsection 3.5.2.2.1.4, the following statement is made: ACI 201.2R was not used as guidance for concrete mix proportions, but ACI 211.1-74 was used. ACI 211.1-74 provides guidance for producing high-density, low permeability concrete mix designs similar to ACI 201.2R. Provide a comparison of the similarities and differences between ACI 201.2R and ACI 211.1-74 for concrete mix proportion designs as they relate to HNP concrete specifications.

RESPONSE
The design of concrete mix in contact with the Containment liner (LRA Table 3.5.1, Item 3.5.1 06) at HNP was in accordance with ACI 211.1-74, "Recommended Practice for Selecting Proportions for Normal and Heavy Weight Concrete," and also in accordance with Article CC-2232 of the ASME Code Section III, Division 2/ACI 359 Code [FSAR 3.8.1.6.1(f)]. LRA Section 3.5.2.2.1.4 discusses loss of material due to corrosion for the Containment liner, liner anchors, and integral attachments. HNP FSAR Section 3.8.1.5.4 states "The alkaline environment of the concrete adequately protects embedded steel parts from corrosion." ACI 201.2R (Section 4.5.1.1) states "Low water-cement ratios produce less permeable concrete and thus provide greater assurance against corrosion." Therefore, water-cement ratio is of primary importance in the discussion provided in the LRA Section 3.5.2.2.1.4.

Selection of the water-cement methodology is the same between the ACI 211.1-74 [Table 5.3.4(b)] and ACI 201.2R, "Guide to Durable Concrete." ACI 211-74 specifies a maximum water-cement ratio of 0.50 for "All other structures" with a footnote that it is based on ACI 201. ACI 201.2R (Section 1.4.2) also specifies a maximum water-cement ratio of 0.50 for "All other structures." The Containment concrete should be included in the "All other structures" category. The actual concrete mix designs at HNP for the Containment concrete were within the water-cement ratios specified in both ACI Codes.

Air entrainment is also an important element in designing a durable, low permeable concrete. Selection of the air content is similar between the two ACI codes. ACI 211-74 (Table 5.3.3) specifies an approximate average air content of 6% for ¾" aggregate and 4 ½ % for 1 ½" aggregate and adds a statement in Section 5.3.3 to see ACI 201 on air content recommendations. ACI 201.2R (Table 1.4.3) recommends an average air content of 5% for ¾" aggregate and 4 ½ % for 1 ½" aggregate with a 1 ½ % tolerance (or 6 ½ % and 6 % respectively). The actual mix designs at HNP for the Containment allowed up to 8% air entrainment for two of the three mixes for the Containment (using ? ¾" maximum size aggregate). This is slightly higher than the 6 ½ % and 6 %. However, the concrete mix designs used at HNP allowed the higher air content while still exceeding the concrete design strength requirements

ACI 201.2R (Sections 1.4 and 1.4.4) recommends suitable materials for producing durable, low permeable concrete. While not specifically discussed in ACI 211-74, the HNP FSAR (Section 3.8.1.6.1) and the original concrete specification identify the concrete materials specifications used at HNP, which are consistent with ACI 201.2R.

ACI 201.2R (Section 4.5.1.1) recommends use of lower water cement ratios for concrete in sea or brackish water (0.40) but this is not in ACI 211-74. However, the sea or brackish water is not applicable to HNP.

The original HNP concrete specification specified a water-cement ratio between 0.44 and 0.60 and the air content specified as 4-8% for maximum aggregate size ¾" and 3-6% for maximum aggregate size 1 1/2". The actual mix design for the Containment concrete as discussed above in this response was within the water-cement ratio and air content limits in the original HNP concrete specification.

Based on a review of OE and discussions with engineering, no aging effects have been identified for Containment concrete related to mix designs including loss of material due to corrosion.

Details are available at HNP for review in the bases and other reference documents.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained in detail the similarities and differences between ACI 201.2R and ACI 211.1-74, which was used at HNP as guidance for concrete mix proportions. This question is resolved.

Question No. 3.5.1-10-JW-01

REQUEST
LRA Table 3.5.1, Item 3.5.1-10, refers to LRA Subsection 3.5.2.2.1.7 in the discussion column. In Subsection 3.5.2.2.1.7, the following statement is made: (2) to be susceptible to SCC, stainless steel must be subjected to both high temperature (>140 degrees F) and an aggressive chemical environment. Provide the maximum operating temperatures for the HNP components associated with item 3.5.1-10.

RESPONSE
The maximum operating temperature which the applicable stainless steel penetrations are subject to is 668 °F for several sampling lines. However, none of the applicable stainless steel components associated with LRA Table 3.5.1, Item 3.5.1-10 are subject to an aggressive chemical environment. According to HNP aging management review methodology, both high temperature (>140 °F) and an aggressive chemical environment are required for the SCC aging effect to be applicable. The basis document for determining aging effects for stainless steel material is available for review at HNP.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has provided the maximum operating temperatures for the HNP components associated with LRA Table 3.5.1, item 3.5.1-10. This question is resolved.

Question No. 3.5.1-26-JW-01

REQUEST
LRA Table 3.5.1, Item 3.5.1-26, is associated with GALL Report item III.A3-5. Provide HNP original concrete specifications to confirm that existing concrete had air content of 3% to 6% and water to cement ratio of 0.35-0.45 when poured.

RESPONSE
LRA Table 3.5.1, Item 3.5.1-26, is associated with GALL Report item III.A3-6, not GALL Report item III.A3-5. LRA Table 3.5.1, Item 3.5.1-26 has further information provided in LRA Section 3.5.2.2.2.2.1.

The actual concrete mix design for the Class I structures monitored by the Structures Monitoring Program had air content ranging from 3% to 8% and water-cement ratios up to 0.50. The actual concrete mix design for the non-Class I structures monitored by the Structures Monitoring Program had air content ranging from 3% to 8% and water-cement ratios up to 0.592.

Based on the actual mix designs exceeding the limits in NUREG-1801, LRA Section 3.5.2.2.2.2.1 states that HNP will examine inaccessible non-Class I concrete used for the structures in scope for License Renewal when excavated for any reason. LRA Table Item 3.5.1-26 states the Structures Monitoring Program is used to manage aging effects of loss of material and cracking due to freeze thaw for accessible concrete for the safety related and non-safety related structures. In addition, while not currently stated in LRA Section 3.5.2.2.2.2.1 or Table Item 3.5.1-26, all inaccessible concrete (non-Class I and Class I) will be examined for loss of material and cracking when below-grade concrete is exposed for any reason prior to backfilling. This is stated in LRA Program B.2.31, in the Enhancements for the Scope of Program and for the Parameters Monitored/Inspected.

Details are available at HNP for review in the bases and other reference documents.

For clarification, LRA Section 3.5.2.2.2.2.1 will be revised to state inaccessible Class I concrete used for the structures in scope of License Renewal will be examined for loss of material and cracking when below-grade concrete is excavated for any reason. On the basis of this response, the LRA will be amended to incorporate this clarification to LRA Section 3.5.2.2.2.2.1.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has provided the air content and water-cement ratios for the concrete used in Class I and non-Class 1 structures at HNP during construction. The applicant stated that it will amend LRA Section 3.5.2.2.2.2.1 to state that inaccessible Class I concrete used for the structures in scope of license renewal will be examined for loss of material and cracking when below-grade concrete is excavated for any reason. This question is resolved.

Question No. 3.5.1-32-JW-01

REQUEST
LRA Table 3.5.1, Item 3.5.1-32, refers to LRA Subsections 3.5.2.2.2.1 and 3.5.2.2.2.2.5 in the discussion column. In Subsection 3.5.2.2.2.2.5, the following statement is made: For inaccessible areas in structures outside the Containment Building, safety related, Class 1 concrete was constructed to ACI 211.1-74, which provides guidance for producing high-density, low permeability concrete similar to ACI 201.2R for concrete mix designs. Therefore, no aging management program is required for inaccessible areas in safety related structures outside the Containment Building. However, Table 1 line 3.5.1-32 is referenced in AMR Tables 3.5.2-2, 3.5.2-10, 3.5.2-12, 3.5.2-17, 3.5.2-27 and 3.5.2-28 for concrete exterior below grade and concrete foundation for managing the aging effect of change in material properties with the Structures Monitoring Program. Explain the contradiction since these six AMR tables are for safety related structures and based on the statement above no aging management program is required.

RESPONSE
HNP License Renewal inadvertently included Table 1 line item 3.5.1-32 on AMR Tables 3.5.2-2, 3.5.2-10, 3.5.2-12, 3.5.2-17, 3.5.2-27 and 3.5.2-28 for the concrete exterior below grade and concrete foundation component/commodity groups. Table 1 line item 3.5.1-32 should be removed from AMR Tables 3.5.2-2, 3.5.2-10, 3.5.2-12, 3.5.2-17, 3.5.2-27 and 3.5.2-28 for the concrete exterior below grade and concrete foundation component/commodity groups.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant explained that LRA Table 1, item 3.5.1-32 was inadvertently included on AMR Tables 3.5.2-2, 3.5.2-10, 3.5.2-12, 3.5.2-17, 3.5.2-27 and 3.5.2-28. The applicant stated that it will amend the previously listed LRA tables to removed AMR line items associated with Table 1, item 3.5.1-32. This question is resolved.

Question No. 3.5.2-2-JW-01

REQUEST
In LRA Table 3.5.2-2 on page 3.5-83 for AMR component phase bus enclosure assemblies, material aluminum in an air-indoor environment, Note 572 is referenced. Note 572 states: The component phase bus assemblies is aligned with III.B2-7 because it has the same material, environment, aging effect, and aging management program; although it is not the same NUREG-1801 component support members; welds, bolted connections, support anchorage to building structure. However, this Table 2 AMR line item is aligned with the GALL Report, Volume 2, item III.B3-2. Explain the discrepancy between the GALL Report's alignment referenced in Note 572 and the GALL Report's alignment shown for this Table 2 AMR line item.

RESPONSE
The basis document has the following text for Note 572:

> The components "Phase Bus Assemblies" are aligned with III.B2-7 or III.B3-2 or III.B3-5 because they have the same material, environment, aging effect and aging management program although they are not the same NUREG-1801 component "Support members; welds, bolted connections, support anchorage to building structure." The basis document is available for review at HNP.

This Note 572 change inadvertently did not get incorporated into the LRA before submittal to the NRC. III.B3-2 is correct for Table 3.5.2-2 AMR line item for phase bus enclosure assemblies, material aluminum in an air-indoor environment on page 3.5-83 of the LRA.

The revised Note 572 applies to other locations in the LRA as well as follows:

> Table 3.5.2-25, page 3.5-169 - GALL Report, Volume 2, item B2-7 is correct for AMR component phase bus enclosure assemblies, material aluminum in an air-outdoor environment.
>
> Table 3.5.2-26, page 3.5-177 - GALL Report, Volume 2, item B3-2 is correct for AMR component phase bus enclosure assemblies, material aluminum in an air-indoor environment.

On the basis of this response, the LRA will be amended to revise Note 572 to agree with the basis document.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 572 for LRA Table 3.5.2-2 AMR line item should also reference the GALL Report, Volume 2, item III.B3-2. Note 572 was changed in the HNP basis document but the change did not get incorporated into the LRA before submittal. The applicant stated that it will amend the LRA to revise Note 572 to include the GALL Report, Volume 2, item III.B3-2. This question is resolved.

Question No. 3.5.2-2-JW-02

REQUEST
In LRA Table 3.5.2-2 on page 3.5-83 for AMR component phase bus enclosure assemblies, material stainless steel in an air-indoor environment, Note 572 is referenced. Note 572 states: The component phase bus assemblies is aligned with III.B2-7 because it has the same material, environment, aging effect, and aging management program; although it is not the same NUREG-1801 component support members; welds, bolted connections, support anchorage to building structure. However, this Table 2 AMR line item is aligned with the GALL Report, Volume 2, item III.B3-5. Explain the discrepancy between the GALL Report's alignment referenced in Note 572 and the GALL Report's alignment shown for this Table 2 AMR line item.

RESPONSE
Same response as for 3.5.2-2-JW-01. Note 572 will be revised.

III.B3-5 is correct for Table 3.5.2-2 AMR line item for phase bus enclosure assemblies, material stainless steel in an air-indoor environment on page 3.5-83 of the LRA.

The revised Note 572 applies to one other location in the LRA as well as follows:

> Table 3.5.2-26, page 3.5-177 - GALL Report, Volume 2, item III.B3-5 is correct for AMR component phase bus enclosure assemblies, material stainless steel in an air-indoor environment.

On the basis of this response, the LRA will be amended to revise Note 572 to agree with the basis document, as stated in response to NRC question 3.5.2-2-JW-01.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 572 for LRA Table 3.5.2-2 AMR line item should also reference the GALL Report, Volume 2, item III.B3-5. Note 572 was changed in the HNP basis document but the change did not get incorporated into the LRA before submittal. The applicant stated that it will amend the LRA to revise Note 572 to include GALL Report, Volume 2, item III.B3-5. This question is resolved.

Question No. 3.5.2-7-JW-01

REQUEST
In LRA Table 3.5.2-7 on page 3.5-95 for AMR component supports for non-ASME piping & components, material stainless steel in an air-outdoor environment, Note 573 is referenced. Note 573 states: The HNP AMR methodology concluded that stainless steel in the air-outdoor environment has no aging effect. Provide the HNP AMR methodology where this conclusion is substantiated.

RESPONSE
The HNP methodology is substantiated in the basis documents located at HNP. The HNP methodology is based on industry aging effects tools for structural and mechanical component materials. In summary, the Air-Outdoor environment at HNP is subject to normal periodic wetting but is not exposed to an aggressive environment from any nearby industrial facilities or to a salt water environment which could have the potential to concentrate contaminates and cause aging effects for stainless steel. In addition, there is no HNP operating experience which indicates aging effects for stainless steel in the Air-Outdoor environment has occurred.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that the air-outdoor environment at HNP is subject to normal periodic wetting, but is not exposed to an aggressive environment from any nearby industrial facilities or to a salt water environment which could have the potential to cause aging effects for stainless steel. Also, HNP does not have a history of aging effects for stainless steel in the HNP air-outdoor environment. This question is resolved.

Question No. 3.5.2-10-JW-01

REQUEST
In LRA Table 3.5.2-10 on page 3.5-102 for AMR component concrete exterior below grade, material reinforced concrete in a soil environment, aging effect cracking, Table 1 item 3.5.1-28, Note 537 is referenced. Note 537 states: HNP does not have a porous concrete subfoundation and does not implement a de-watering system; therefore this aging effect is not applicable and no aging management is required. Explain why Note 537 is associated with Table 1 item 3.5.1-28, which addresses cracks and distortion due to increased stress levels from settlement.

RESPONSE
Note 537 is incorrectly associated with concrete exterior below grade, material reinforced concrete in a soil environment in LRA Table 3.5.2-10 on page 3.5-102.

On the basis of this response, the LRA will be amended to remove Note 537 from concrete exterior below grade, material reinforced concrete in a soil environment in LRA Table 3.5.2-10 on page 3.5-102.

Note 537 is also incorrectly associated with concrete exterior below grade, material reinforced concrete in a soil environment in the following locations in the LRA:

Table 3.5.2-17 on page 3.5-131
Table 3.5.2-26 on page 3.5-173

On the basis of this response, the LRA will be amended to also remove Note 537 from concrete exterior below grade, material reinforced concrete in a soil environment in Table 3.5.2-17 on page 3.5-131, Table 3.5.2-26 on page 3.5-173.

Note 537 is incorrectly associated with concrete foundation, material reinforced concrete in a soil environment [Table 1 item 3.5.1-28 III.A8-2 (T-08)] in the following locations in the LRA:

Table 3.5.2-27 on page 3.5-181

On the basis of this response, the LRA will be amended to also remove Note 537 from concrete foundation, material reinforced concrete in a soil environment [Table 1 item 3.5.1-28, III.A8-2 (T-08)] in Table 3.5.2-27 on page 3.5-181.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 537 has been incorrectly associated with LRA Table 3.5.2-10 AMR line item. The applicant stated that it will amend the LRA Table 3.5.2-10 AMR line item to remove Note 537. This question is resolved.

Question No. 3.5.2-17-JW-01

REQUEST
In LRA Table 3.5.2-17 on page 3.5-129 for AMR component canal and pool gates, material stainless steel in an air-indoor environment, no aging effect, Note 545 is referenced. Note 545 discusses new fuel storage racks as being stainless steel. Explain why Note 545 is associated with the components canal and pool gates.

RESPONSE
Note 545 for AMR component canal and pool gates, material stainless steel in an air-indoor environment was incorrectly assigned and should be changed to Note 540. Note 540 should be revised to include Canal and Pool Gates as follows:

> The components "Steel Components: All structural steel," "Steel Components: Fuel Pool Liner," "Floor Drains," "Sump Screens" or "Canal and Pool Gates" are aligned with III.B5-5 and/or III.B5-6 as "Miscellaneous Structures" because they have the same material, environment, aging effect and aging management program although they are not the same NUREG-1801 component "Support members; welds, bolted connections, support anchorage to building structure."

The stainless steel canal and pool gates still have no aging effects but this change provides a more consistent use of the plant-specific notes.

On the basis of this response, the LRA will be amended to revise Note 540 as stated above in the response and AMR component canal and pool gates, material stainless steel in an air-indoor environment will be revised to delete Note 545 and add Note 540.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 545 has been incorrectly associated with LRA Table 3.5.2-17 AMR line item and should be changed to Note 540. The applicant stated that it will amend the LRA Table 3.5.2-17 AMR line item to change Note 545 to Note 540 and also revise Note 540. This question is resolved.

Question No. 3.5.2-17-JW-02

REQUEST
In LRA Table 3.5.2-17 on page 3.5-131 for AMR component concrete exterior below grade, material reinforced concrete in a soil environment, aging effect cracking, Table 1 item 3.5.1-28, Note 537 is referenced. Note 537 states: HNP does not have a porous concrete subfoundation and does not implement a de-watering system; therefore this aging effect is not applicable and no aging management is required. Explain why Note 537 is associated with Table 1 item 3.5.1-28, which addresses cracks and distortion due to increased stress levels from settlement. (Reference question 3.5.2-10-JW-01)

RESPONSE
The response to NRC question 3.5.2-10-JW-01 adequately answers this question.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 537 has been incorrectly associated with LRA Table 3.5.2-17 AMR line item. The applicant stated that it will amend the LRA Table 3.5.2-17 AMR line item to remove Note 537. This question is resolved.

Question No. 3.5.2-17-JW-03

REQUEST
In LRA Table 3.5.2-17 on page 3.5-132 for AMR component concrete interior, material reinforced concrete in an air-indoor environment, aging effect change in material properties, Table 1 item 3.5.1-33, Notes I and 502 are referenced. Note I states: Aging effect in NUREG-1801 for this component, material and environment combination is not applicable. Note 502 states: Change in material properties due to elevated temperature is not an aging effect because the concrete is not subjected to general area temperature >150°F or local area temperatures >200°F. Explain why Notes I and 502 state that there are no aging effects and yet there is the aging effect change in material properties with AMP Structures Monitoring shown for this Table 2 AMR line item.

RESPONSE
The temperature range for the Fuel Handling Building is 60°F to 115.5°F. Note 502 states that there are no aging effects due to elevated temperature for this building. Therefore, applying Notes I and 502 to this line item is correct. However, the aging effect requiring management and aging management programs should both show ”None.”

On the basis of this response, the LRA and the basis document will be amended to change the aging effect requiring management and the aging management program column items to “None” for LRA Table 3.5.2-17 on page 3.5-132 for AMR component concrete interior, material reinforced concrete in an air-indoor environment.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant’s response acceptable because the applicant has explained that for the LRA Table 3.5.2-17 AMR line item the aging effect requiring management and aging management programs should both show None. The applicant stated that it will amend this LRA Table 3.5.2-17 AMR line item to change the aging effect requiring management and the aging management program column items to None. This question is resolved.

Question No. 3.5.2-17-JW-04

REQUEST
In LRA Table 3.5.2-17 on page 3.5-134 for AMR component fire hose stations, material carbon steel in a borated water leakage environment, aging effect loss of material, Table 1 item 3.5.1-55, Note 544 is referenced. Note 544 references GALL Report item III.B5-7 which has nothing to do with boric acid corrosion. Explain why Note 544 is referenced instead of Note 539 which makes reference to GALL Report item III.B5-8 that addresses boric acid corrosion.

RESPONSE
Note 539 should be referenced instead of Note 544 in LRA Table 3.5.2-17 on page 3.5-134 for AMR component fire hose stations, material carbon steel in a borated water leakage environment, aging effect loss of material.

On the basis of this response, LRA Table 3.5.2-17 on page 3.5-134 for AMR component fire hose stations, material carbon steel in a borated water leakage environment, aging effect loss of material will be amended to change Note 544 to Note 539.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 544 has been incorrectly associated with this LRA Table 3.5.2-17 AMR line item and should be changed to Note 539. The applicant stated that it will amend this LRA Table 3.5.2-17 AMR line item to change Note 544 to Note 539. This question is resolved.

Question No. 3.5.2-17-JW-05

REQUEST
In LRA Table 3.5.2-17 on page 3.5-136 for AMR component new fuel storage rack, material stainless steel in an air-indoor environment, aging effect None, Table 1 item 3.5.1-59, Note 545 is referenced. Note 545 references GALL Report, item III.B5-5. Explain why GALL Report item VII.A1-1 is shown for this Table 2 AMR line item when neither Note 545 or Table 1, item 3.5.1-59 reference GALL Report item VII.A1-1.

RESPONSE
NUREG-1801 (GALL) assumed that the new fuel storage racks would be carbon steel and aligned it to the carbon steel GALL Report item VII.A1-1. However, the HNP new fuel storage racks are stainless steel and GALL Report item VII.A1-1 does not apply. There is no stainless steel GALL Report item for the new fuel storage racks. Note 545 clarifies that the new fuel storage racks are stainless steel components in an Air-indoor environment and would be aligned to the more applicable GALL Report item III.B5-5, with the same material, environment, aging effect (none), and aging management program (none). However, for clarification, LRA Table 3.5.2-17 on page 3.5-136 for AMR component new fuel storage rack, material stainless steel in an air-indoor environment, aging effect None, Table 1 item 3.5.1-59 will be revised to replace VII.A1-1 (A-94) with III.B5-5. In addition, Note 545 will be revised as follows:

> NUREG-1801 assumes New Fuel Storage Racks are carbon steel, in an Air-Indoor environment, with aging effects (NUREG-1801 item VII.A1-1). However, the HNP New Fuel Storage Racks are stainless steel. Stainless steel in an Air-Indoor environment has no aging effects. The New Fuel Storage Racks are aligned with NUREG-1801 Item III.B5-5 because the New Fuel Storage Racks have the same material, environment, aging effect (none) and aging management program (none) although they are not the same NUREG-1801 component "Support members; welds, bolted connections, support anchorage to building structure."

On the basis of this response, the LRA will be amended in LRA Table 3.5.2-17 on page 3.5-136 for AMR component new fuel storage rack, material stainless steel in an air-indoor environment, aging effect None, Table 1 item 3.5.1-59 to replace VII.A1-1 (A-94) with III.B5-5 (TP-5) and Note 545 will be amended as stated above in this response.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that the HNP new fuel storage racks are stainless steel and GALL Report item VII.A1-1 does not apply. The applicant stated that it will amend this LRA Table 3.5.2-17 AMR line item to replace VII.A1-1 with III.B5-5 and revise Note 545 for clarification. This question is resolved.

Question No. 3.5.2-17-JW-06

REQUEST
In LRA Table 3.5.2-17 on page 3.5-138 for AMR components roof membrane/built-up and seals and gaskets, Note 553 is referenced. Note 553 states in its second sentence: However, these elastomers are in the Group 3 structures rather than a Group 6 structure (III.A6-12). Table 3.5.2-17 is for the fuel handling building. Explain why the note refers to GALL Report Group 3 structures instead of GALL Report Group 5 structures, fuel storage facility.

RESPONSE
The basis document dedicated Note 553 for the roof membrane/built-up and seals and gaskets in the Fuel Handling Building. The Fuel Handling Building is a GALL Report Group 5 structure. The basis document does not make reference to Group 5 structures in Note 553, which was omitted in the LRA. Therefore, Note 553 should also include reference to GALL Report Group 5 structures.

Additionally, the basis document dedicated Note 553 for the roof membrane/built-up and seals and gaskets in the Tank Area/Building (RAI 3.5.2-27-JW-04) and the Diesel Fuel Oil Storage Tank Building. The Tank Area/Building and the Diesel Fuel Oil Storage Tank Building are GALL Report Group 8 structures. The basis document does not make reference to Group 8 structures in Note 553, which was also omitted in the LRA. Therefore, Note 553 should also include reference to GALL Report Group 8 structures.

On the basis of this response, the LRA and the basis document will be amended to change Note 553 to include GALL Report Group 5 and Group 8 structures.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 553 for this LRA Table 3.5.2-17 AMR line item should also reference the GALL Report Group 5 structures. The applicant stated that it will amend this LRA Table 3.5.2-17 AMR line item to change Note 553 to include GALL Report Group 5 structures. This question is resolved.

Question No. 3.5.2-21-JW-01

REQUEST
In LRA Table 3.5.2-21 on page 3.5-148 for AMR component concrete: exterior below grade, aging effect cracking and Table 1 item 3.5.1-28 there is only Note A. All other Table 2 AMR line items associated with Table 1 item 3.5.1-28 have also a Note 530. Explain why Note 530 does not apply to this Table 2 AMR line item. Explanation should also apply to Table 3.5.2-21 on page 3.5-149 for the AMR component concrete: foundation.

RESPONSE
The basis document applies Note 530 to AMR line items to address aging effects for concrete due to settlement. However, the basis document did not apply Note 530 to (2) non-safety related structures; namely the Security Building (LRA Table 3.5.2-21) and the Switchyard Relay Building (LRA Table 3.5.2-24), which was also omitted from the LRA. Therefore, Note 530 should be included for the Security Building (Table 1 Item 3.5.1-28 on LRA Table 3.5.2-21) for AMR component Concrete: Exterior Below Grade (LRA Page 3.5.1-148) and for AMR component Concrete: Foundation (LRA Page 3.5-149). Note 530 should also be included for the Switchyard Relay Building (Table 1 Item 3.5.1-28 on Table 3.5.2-24) for AMR component Concrete: Foundation (LRA Page 3.5-164).

On the basis of this response, the LRA and the basis document will be amended to include Note 530 at two locations for the Security Building (3.5.1-28 for AMR components Concrete: Exterior Below Grade, and AMR component Concrete: Foundation) and one location for the Switchyard Relay Building (3.5.1-28 for AMR component Concrete: Foundation).

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 530 was omitted from the LRA at several locations. The applicant stated that Note 530 should be included for the Security Building AMR components concrete: exterior below grade and concrete: foundation. In addition, Note 530 should be included for the Switchyard Relay Building for AMR component concrete: foundation. The applicant stated that it will amend the LRA to include Note 530 at two AMR line item locations for the Security Building Table 3.5.2-21 and one AMR line item location for the Security Relay Building Table 3.5.2-24. This question is resolved.

Question No. 3.5.2-26-JW-01

REQUEST
In LRA Table 3.5.2-26 on page 3.5-173 for AMR component concrete: exterior above grade, the aging effect cracking is associated with Table 1 item 3.5.1-32. Explain why the aging effect cracking is associated with Table 1 item 3.5.1-32 instead of change in material properties.

RESPONSE
LRA Table 1 item 3.5.1-32 in Table 3.5.2-26 on page 3.5-173 should be removed because the Turbine Building does not have exterior above grade concrete in a water-flowing environment associated with GALL Report item III.A3-7. This will be consistent with other Group III structures once this change is made (See LRA Table 3.5.2-2 and LRA Table 3.5.2-10 as examples for where concrete: exterior above grade is not associated with GALL Report Item III.A3-7.)

On the basis of this response, the LRA and the basis document will be amended to delete the line in Table 3.5.2-26 on page 3.5-173 for Table 1 item 3.5.1-32 for AMR component concrete: exterior above grade.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that the HNP Turbine Building does not have exterior above grade concrete in a water-flowing environment. The applicant stated that it will amend the LRA to delete the Table 3.5.2-26 AMR line item for component concrete: exterior above grade associated with LRA Table 1, item 3.5.1-32. This question is resolved.

Question No. 3.5.2-26-JW-02

REQUEST
In LRA Table 3.5.2-26 on page 3.5-173 for AMR component concrete exterior below grade, material reinforced concrete in a soil environment, aging effect cracking, Table 1 item 3.5.1-28, Note 537 is referenced. Note 537 states: HNP does not have a porous concrete subfoundation and does not implement a de-watering system; therefore this aging effect is not applicable and no aging management is required. Explain why Note 537 is associated with Table 1 item 3.5.1-28, which addresses cracks and distortion due to increased stress levels from settlement. (Reference question 3.5.2-10-JW-01 and 3.5.2-17-JW-02)

RESPONSE
The response to NRC question 3.5.2-10-JW-01 adequately answers this question.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 537 has been incorrectly associated with this LRA Table 3.5.2-26 AMR line item. The applicant stated that it will amend this LRA Table 3.5.2-26 AMR line item to remove Note 537. This question is resolved.

Question No. 3.5.2-26-JW-03

REQUEST
In LRA Table 3.5.2-26 on page 3.5-177 for AMR component phase bus enclosure assemblies, material aluminum in an air-indoor environment, aging effect None, Table 1 item 3.5.1-58, Note 572 is referenced. Note 572 references GALL Report item III.B2-7. Explain why GALL Report item III.B2-7 is discussed in the note since GALL Report item III.B3-2 is shown for this Table 2 AMR line item and Table 1 item 3.5.1-58 does not reference GALL Report item III.B2-7.

RESPONSE
This question is answered in response to 3.5.2-2-JW-01.

On the basis of this response, the LRA will be amended to revise Note 572 to agree with the basis document, as stated in response to NRC question 3.5.2-2-JW-01.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 572 for this LRA Table 3.5.2-26 AMR line item should also reference GALL Report Volume 2, item III.B3-2. Note 572 was changed in the HNP basis document but the change did not get incorporated into the LRA before submittal. The applicant stated that it will amend the LRA to revise Note 572 to include GALL Report Volume 2, item III.B3-2. This question is resolved.

Question No. 3.5.2-26-JW-04

REQUEST
In LRA Table 3.5.2-26 on page 3.5-177 for AMR component phase bus enclosure assemblies, material stainless steel in an air-indoor environment, aging effect None, Table 1 item 3.5.1-59, Note 572 is referenced. Note 572 references GALL Report item III.B2-7. Explain why GALL Report item III.B2-7 is discussed in the note since GALL Report item III.B3-5 is shown for this Table 2 AMR line item and Table 1 item 3.5.1-59 does not reference GALL Report item III.B2-7.

RESPONSE
This question is answered in the response to 3.5.2-2-JW-01 and 3.5.2-2-JW-02.

On the basis of this response, the LRA will be amended to revise Note 572 to agree with the basis document, as stated in response to NRC question 3.5.2-2-JW-01.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 572 for this LRA Table 3.5.2-26 AMR line item should also reference GALL Report Volume 2, item III.B3-5. Note 572 was changed in the HNP basis document but the change did not get incorporated into the LRA before submittal. The applicant stated that it will amend the LRA to revise Note 572 to include GALL Report Volume 2, item III.B3-5. This question is resolved.

Question No. 3.5.2-27-JW-01

REQUEST
In LRA Table 3.5.2-27 on page 3.5-181 for AMR component concrete foundation, material reinforced concrete in a soil environment, aging effect cracking, Table 1 item 3.5.1-28, Note 537 is referenced. Note 537 states: HNP does not have a porous concrete subfoundation and does not implement a de-watering system; therefore this aging effect is not applicable and no aging management is required. Explain why Note 537 is associated with Table 1 item 3.5.1-28, which addresses cracks and distortion due to increased stress levels from settlement. (Reference questions 3.5.2-10-JW-01, 3.5.2-17-JW-02, and 3.5.2-26-JW-02).

RESPONSE
The response to NRC question 3.5.2-10-JW-01 adequately answers this question.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 537 has been incorrectly associated with this LRA Table 3.5.2-27 AMR line item. The applicant stated that it will amend this LRA Table 3.5.2-27 AMR line item to remove Note 537. This question is resolved.

Question No. 3.5.2-27-JW-02

REQUEST
In LRA Table 3.5.2-27 on page 3.5-182 for AMR component concrete roof slab, material reinforced concrete in an air-outdoor environment, aging effect loss of material and cracking, Table 1 item 3.5.1-27 and GALL Report item III.A8-1 are shown. Table 1 item 3.5.1-27 and GALL Report item III.A8-1 are not associated with loss of material and cracking but Table 1 item 3.5.1-26 and GALL Report item III.A8-5 are. Explain why GALL Report item III.A8-1 and Table 1 item 3.5.1-27 are associated with the aging effects for this AMR line item.

RESPONSE
On LRA Table 3.5.2-27, page 3.5-182 for AMR component concrete roof slab, material reinforced concrete in an air-outdoor environment, the first row should be revised as follows:

Loss of Material, Cracking - Structures Monitoring Program - III.A8-5, (T-01) - 3.5.1-26 - Note A

The second row should be revised as follows:

Cracking - Structures Monitoring Program - III.A8-1 (T-03) - 3.5.1-27 - Note A, 504

On the basis of this response, LRA Table 3.5.2-27, page 3.5-182 for AMR component concrete roof slab, material reinforced concrete in an air-outdoor environment will be changed as follows.

The first row should be revised as follows:

Loss of Material, Cracking - Structures Monitoring Program - III.A8-5, (T-01) - 3.5.1-26 - Note A

The second row should be revised as follows:

Cracking - Structures Monitoring Program - III.A8-1 (T-03) - 3.5.1-27 - Note A, 504

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that for this LRA Table 3.5.2-27 AMR line item the GALL Report Volume 2 item and Table 1 item are incorrect in the LRA. The applicant stated that it will amend this LRA Table 3.5.2-27 AMR line item to change and correct the GALL Report Volume 2 item to III.A8-5 and the LRA Table 1 item to 3.5.1-26. This question is resolved.

Question No. 3.5.2-27-JW-03

REQUEST
In LRA Table 3.5.2-27 on page 3.5-182 for AMR component concrete roof slab, material reinforced concrete in an air-outdoor environment, aging effect cracking, Table 1 item 3.5.1-27 and GALL Report item III.A8-5 are shown. GALL Report item III.A8-5 is not associated with cracking alone but GALL Report item III.A8-1 is. Explain why GALL Report item III.A8-5 is associated with the aging effect for this AMR line item.

RESPONSE
Refer to Response 3.5.2-27-JW-02.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that for this LRA Table 3.5.2-27 AMR line item the GALL Report Volume 2 item is incorrect in the HNP LRA. The applicant stated that it will amend this LRA Table 3.5.2-27 AMR line item to change and correct the GALL Report Volume 2 item to III.A8-1. This question is resolved.

Question No. 3.5.2-27-JW-04

REQUEST
In LRA Table 3.5.2-27 on page 3.5-184 for AMR components roof membrane/built-up and elastomers, Note 553 is referenced. Note 553 states in its second sentence: However, these elastomers are in the Group 3 structures rather than a Group 6 structure (III.A6-12). Table 3.5.2-27 is for the tank area/building. Explain why the note refers to GALL Report Group 3 structures instead of GALL Report Group 8 structures, steel tanks and missile barriers.

RESPONSE
The response to NRC question 3.5.2-17-JW-06 adequately answers this question.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that Note 553 for this LRA Table 3.5.2-27 AMR line item should also reference GALL Report Group 8 structures. The applicant stated that it will amend this LRA Table 3.5.2-27 AMR line item to change Note 553 to include GALL Report Group 8 structures. This question is resolved.

Question No. 3.5.2-28-JW-01

REQUEST
In LRA Table 3.5.2-28 on page 3.5-191 for AMR component seismic joint filler, material elastomer in an air-indoor environment, GALL Report items VII.G-1 and VII.G-2 are shown. GALL Report item VII.G-2 is not associated with an air-indoor environment but GALL Report item VII.G-1 is. Explain why GALL Report item VII.G-2 is associated with the environment for this AMR line item.

RESPONSE
GALL Report item VII.G-2 was associated with an air-indoor environment because NUREG-1800 Table 3.3-1 and NUREG-1801 Table 3, Summary of Aging Management Programs for the Auxiliary System Evaluated in Chapter VII of the GALL Report item 3.3-61 included both air-outdoor and air-indoor in the component description. However, for clarity, GALL Report item VII.G-2 will be removed from LRA Table 3.5.2-28 on page 3.5-191 for AMR component seismic joint filler, material elastomer in an air-indoor environment.

On the basis of this response, the LRA will be amended to remove GALL Report item VII.G-2 from LRA Table 3.5.2-28 on page 3.5-191 for AMR component seismic joint filler, material elastomer in an air-indoor environment.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that GALL Report item VII.G-2 was associated with an air-indoor environment because SRP-LR Table 3.3-1, item 61 included both air-outdoor and air-indoor in the component description. The applicant stated that it will amend this LRA Table 3.5.2-28 AMR line item for component seismic joint filler to remove GALL Report item VII.G-2 for clarity. This question is resolved.

Question No. 3.5.2-29-JW-01

REQUEST
In LRA Table 3.5.2-29 on page 3.5-192 for AMR component cable tray, conduit etc., material stainless steel and carbon steel, Note 555 is referenced. Note 555 states: Buried conduits that connect to Class1 manholes have a designed water tight clamping arrangement. Provide a drawing showing the water tight clamping arrangement with the components identified. In LRA Table 3.5.2-29 on page 3.5-197 for AMR component seals and gaskets, material elastomer in a soil environment, Note 555 is again referenced. Note 555 states: The HNP AMR methodology concluded that the neoprene boot material has no aging effect in soil and, etc. Provide the HNP AMR methodology where this conclusion is substantiated.

RESPONSE
The water tight clamping arrangement for the manholes is shown on FSAR Figure 3.8.4-23 and is available at HNP for review.
The HNP AMR methodology for concluding the neoprene boot material has no aging effect in soil is included in the HNP AMR basis calculation. The HNP methodology is based on industry aging effects tools for structural and mechanical component materials.

However, in LRA Table 3.5.2-29 on page 3.5-192 for AMR component cable tray, conduit etc., material stainless steel and carbon steel, the Structures Monitoring Aging Management Program will be deleted and “None” added because there is no direct visual inspection of the stainless steel clamp or carbon steel closure plate in the soil environment. In addition Note 555 will be revised to clarify that water intrusion through the area where the buried conduits connect to the Class I manholes will be detected from inspections inside the manholes under the commodity, Concrete: Interior, using the Structures Monitoring Program.

On the basis of this response, the LRA will be amended in LRA Table 3.5.2-29 on page 3.5-192 for AMR component cable tray, conduit etc., material stainless steel and carbon steel in a soil environment to delete the Structures Monitoring Program and add “None.” In addition Note 555 will be revised as follows:

“Buried conduits that connect to Class 1 manholes have a designed water tight clamping arrangement. The clamping arrangement provided includes a carbon steel support structure, stainless steel clamps, and a neoprene boot. The purpose of the clamping arrangement is to prevent water intrusion into the manholes.

Due to the inaccessible location of the arrangement and potential damage to the safety related cable, no direct visual inspection is planned for the buried clamping arrangement in the soil. However, degradation of the clamping arrangement leading to water intrusion into the manholes can be determined from inspections performed from inside the manhole. The interior of the manholes (included with Commodity, Concrete: Interior) will continue to be inspected by the Structures Monitoring Program for water intrusion, including the area where the buried conduits connect to the Class I manholes.

The HNP AMR methodology concluded that the neoprene boot material has no aging effect in soil.

The HNP AMR methodology concluded that carbon steel and stainless steel in soil have the aging effect of loss of material.”

A License Renewal Application amendment is required.

STAFF EVALUATION

The staff finds the applicant's response acceptable because the applicant has clarified that there is actually no direct visual inspection of the stainless steel clamp or carbon steel closure plate in a soil environment for this LRA Table 3.5.2-29 AMR line item. Also the HNP AMR basis calculation was proved which provided the methodology for concluding the neoprene boot material has no aging effect in soil. The applicant stated that it will amend this LRA Table 3.5.2-29 AMR line item for component cable tray, conduit etc., for carbon steel and stainless steel material to delete the Structures Monitoring Program and add "None" because there is no direct visual inspection of the stainless steel clamp or carbon steel closure plate in a soil environment. In addition, Note 555, which is associated with this AMR line item, will be revised to clarify that degradation of the clamping arrangement leading to water intrusion into manholes can be determined from inspections performed from the inside of the manholes under the Structures Monitoring Program. This question is resolved.

Question No. 3.5.2-29-JW-02

REQUEST
In LRA Table 3.5.2-29 on page 3.5-197 for AMR component siding, Notes A and 544 are referenced. The component siding is different from the components associated with GALL Report Volume 2 item III.B.5-7 which is shown for this AMR line item. Explain why the note is an A, consistent component, versus a C, component is different. Note 544 discusses the components non-fire doors, floor drains and fire hose stations, but not siding. Explain why Note 544 is associated with this AMR line item for siding when it does not discuss siding.

RESPONSE
The GALL Report does not include a category for carbon steel siding. However, GALL Report Volume 2 item III.B.5-7 includes a category called miscellaneous structures that has similar material and environment as for carbon steel siding. HNP has included carbon steel siding within this category but omitted to include details of the addition for the component to explanation Note 544 as was similarly done for non-fire doors, floor drains and fire hose stations. Additionally, Standard Note C is more appropriate than Note A for this line item to explain that the component is different, but consistent with NUREG-1801 item for material, environment and aging effect.

On the basis of this response, the LRA and the basis document will be amended to change plant-specific Note 544, LRA page 3.5-201, to include siding. Additionally, for the siding line item on LRA page 3.5-197, the standard Note A will be changed to standard Note C.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has explained that standard Note C is more appropriate than Note A for this line item since the component is different, but consistent with the GALL Report for material, environment and aging effect. In addition, Note 544 for this line item omitted in error the component carbon steel siding. The applicant stated that it will amend this LRA Table 3.5.2-29 AMR line item for component siding to change the standard Note A to Note C. In addition, the LRA will be amended to change plant-specific Note 544 to include siding. This question is resolved.

Question No. 3.5.2-29-JW-03

REQUEST
In LRA Table 3.5.2-29 on page 3.5-196 for AMR component Pipe, material Reinforced Concrete, environment Soil, aging effects: Cracking, Loss of material and Change in material properties; the aging management program shown is Buried Piping and Tanks Inspection Program. A review of the Buried Piping and Tanks Inspection Program shows that the inspection of buried reinforced concrete pipe is not part of the program. Explain why the Buried Piping and Tanks Inspection Program is shown for this line item to manage the aging effects when the component reinforced concrete pipe is not within the scope of the program.

RESPONSE
The LRA inadvertently did not incorporate a basis document change into LRA Table 3.5.2-29. LRA Table 3.5.2-29 should be revised as follows:

> LRA Table 3.5.2-29 on page 3.5-196 for AMR component pipe, material reinforced concrete, in a soil environment, the Buried Piping and Tanks Inspection Program should be deleted and replaced with the Structures Monitoring Program. In addition Note 547 should be revised as follows:

"The reinforced concrete pipe and asbestos cement manifold header are mechanical components utilizing civil materials which do not align with NUREG-1801. The HNP AMR methodology concluded that reinforced concrete and asbestos cement pipe in Raw Water and Air-Outdoor environments and reinforced concrete pipe in a Soil environment have the same aging effects as structural concrete. The Structures Monitoring Program was selected to manage the aging effects of reinforced concrete pipe in a Soil environment and Mechanical aging management programs were selected to manage the aging effects of reinforced concrete and asbestos cement pipe in Raw Water and Air-Outdoor environments."

On the basis of this response, the LRA will be amended in LRA Table 3.5.2-29 on page 3.5-196 for AMR component pipe, material reinforced concrete, in a soil environment to delete the Buried Piping and Tanks Inspection Program and add the Structures Monitoring Program. In addition Note 547 on page 3.5-202 of the LRA will be amended as follows:

> "The reinforced concrete pipe and asbestos cement manifold header are mechanical components utilizing civil materials which do not align with NUREG-1801. The HNP AMR methodology concluded that reinforced concrete and asbestos cement pipe in Raw Water and Air-Outdoor environments and reinforced concrete pipe in a Soil environment have the same aging effects as structural concrete. The Structures Monitoring Program was selected to manage the aging effects of reinforced concrete pipe in a Soil environment and Mechanical aging management programs were selected to manage the aging effects of reinforced concrete and asbestos cement pipe in Raw Water and Air-Outdoor environments."

A License Renewal Application amendment is required.

STAFF EVALUATION

The staff finds the applicant's response acceptable because the applicant explained that the LRA inadvertently did not incorporate a basis document change into LRA Table 3.5.2-29. In LRA Table 3.5.2-29 for AMR component pipe, material reinforced concrete, in a soil environment, the Buried Piping and Tanks Inspection Program should have been deleted and replaced with the Structures Monitoring Program. The applicant stated that it will amend LRA Table 3.5.2-29 for AMR component pipe, material reinforced concrete, in a soil environment to delete the Buried Piping and Tanks Inspection Program and add the Structures Monitoring Program. In addition, Note 547 associated with this AMR line item will be revised accordingly. This question is resolved.

Question No. 3.6-RM-01

REQUEST
Please identify the changes required to the LRA Table 3.6.2.1 for component "high-voltage power cables" and Note "602" to reflect the HNP's response to audit question LRA 3.6.2-1-RM-2.

RESPONSE
Revision to LRA Table 3.6.2-1 and Note “602” is shown below:

Component Commodity	Intended Function	Material	Environment	AERM	AMP	NUREG-1801, Vol. 2 Item	Table 1 Item	Notes
High-Voltage Power Cables	Electrical continuity	Oil-impregnated paper (insulation) Lead (sheath) Organic polymers (outer jacket)	Air-Outdoor	Loss of dielectric strength leading to reduced insulation resistance (IR); electrical failure	Oil-Filled Cable Testing Program			J, 602

Notes for Table 3.6.2-1
602 – The HNP cables are high-voltage, oil-filled, paper insulated, lead-sheathed cables. Lead sheath cables are designed for submergence for extended periods. The impregnation of the paper tape improves the insulation’s electrical resistance and provides an extra layer of defense against moisture ingress. The highly refined oil used for the insulating medium also serves to dissipate heat from the conductors and cools the cable when operating under load. The HNP cables have an Okolene (black polyethylene) outer jacket. Site and industry operating experience has shown this design to be extremely reliable in underground applications. Periodic cable testing will be performed to assure that the effects of aging will be managed during the period of extended operation.

This will require an amendment to the LRA which is being tracked under audit question LRA 3.6.2-1-RM-2

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has identified the material, environment, AERM, and the aging management program for managing the aging effect of high-voltage power cables and proposed an amendment to the LRA Table 3.6.2.1. Additional clarification to this question is provided in response to staff's question, LRA 3.6.2-1-RM-2. This question is resolved.

Question No. 3.6-RM-02

REQUEST
Please describe the maintenance and inspections performed on the switchyard bus and connections including their frequencies to address potential degradation of switchyard connections. Discuss the HNP operating experience.

RESPONSE
Currently, HNP performs thermographic surveys on the switchyard bus and connections on a quarterly basis. For the period of extended operation, thermographic surveys of switchyard connections within the scope of License Renewal will be performed under the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program as described in LRA Subsection B.2.37.

The aluminum bolting hardware used for the connections to the switchyard bus was selected to be compatible with the aluminum connector/conductor coefficient of thermal expansion. This ensures that the contact pressure of the bolt and washer combination used in the connector is maintained to the initial vendor specified torque value. The inscope bolted connections are those used to electrically connect the transmission conductors to the switchyard bus and the main power transformers. HNP design incorporates the use of stainless steel “Belleville” washers on the bolted electrical connections to the main power transformers to compensate for temperature changes, maintain the proper torque and prevent loosening of dissimilar metal connection hardware. This method of assembly is consistent with the good bolting practices recommended in EPRI Technical Report 1003471. A review of site operating experience (OE) is documented in a plant evaluation. This evaluation revealed no switchyard bolted connection failures attributed to aging. This confirms the proper design and installation of HNP transmission conductor bolted connections and demonstrates their reliability.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant described the HNP maintenance and inspections performed on the switchyard bus and connections including its operating experience. The staff's review did not identify any degradation issues which require the applicant to establish an AMP. This question is resolved.

Question No. 3.6-RM-03

REQUEST
In LRA, Table 3.6.2-1, the applicant states that uninsulated ground conductors and connectors have no aging effects requiring management and no AMP is required. Discuss why torque relaxation for bolted connection is not a concern at HNP.

RESPONSE
Torque relaxation of bolted connections on uninsulated ground conductors is not a concern at HNP because all connections are bonded together using the powder weld (i.e., CADWELD®) process. Operating experience has proven that this method of bonding produces a permanent exothermic connection that will not loosen. Therefore, torque relaxation of bolted connections on uninsulated ground conductors is not an aging effect requiring management for the period of extended operation.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has identified that all connections are bonded together using the powder weld (i.e., CADWELD®) process and hence torque relaxation of bolted connections on uninsulated ground conductors is not a concern at HNP. This question is resolved.

Question No. 3.6.2-1-RM-01

REQUEST
In LRA Table 3.6.2-1, plant-specific Note 604, the applicant states that the fuse holders within the scope of the aging management review are used only in radiation monitoring I&C circuits. Provide details about the review criteria used for this determination and also provide details regarding the results of the plant walkdowns performed (number and condition of fuse holders inspected, etc.).

RESPONSE
HNP fuses were screened against the criteria given in NUREG-1801, Section XI.E5. The following is a summary of the HNP screening process.

The vast majority of fuse holders at HNP are located in active devices, such as control panels, switchgear, MCCs and termination cabinets. To discover the population of fuse holders located outside of these active components, a query was developed showing all HNP fuses within the scope of license renewal. This produced a list of approximately 2600 items. Then, control wiring diagrams, plant engineering expertise and the equipment database (EDB) were used to determine which of these within scope fuses were located within an active device, so that they could be eliminated from the process. This reduced the original list down to less than 40 fuses, all of which were installed only in radiation monitoring I&C circuits. A walkdown of the remaining fuses found them to be in an air-conditioned environment with no external signs of aging degradation.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant described the review criteria used and the plant walkdown performed to determine the fuse holders that needed an AMP to manage the aging effect as specified in GALL AMP XI.E5. Based on the review, the staff confirmed that there are no fuse holders which require an AMP to manage the aging effect. This question is resolved.

Question No. 3.6.2-1-RM-02

REQUEST
In LRA Table 3.6.2-1, the applicant states that high-voltage power cables have no aging effects requiring management. The plant-specific Note 602 for these cables states that the HNP PILC cables are similar in design to the Turkey-Point medium voltage cables and were evaluated and accepted by the staff. The staff notes that HNP cables are not the same as Turkey Point cables. HNP cables are oil filled high-voltage cables operated at 230kV. The HNP cable operating characteristic and its life depends on its dielectric properties and the applicant needs to address how it plans to address the aging effects on its technical merit.

The staff requests the applicant to discuss the following: (1) Which AMP addresses periodic testing of insulating oil in the cable system to prevent degradation of its dielectric properties, (2) Which AMP addresses the vendor recommended maintenance for oil-filled cable system during the period of extended operation (PEO), (3) Provide details of periodic visual inspections and walkdowns performed to date and proposed for the PEO to monitor for oil leakage including checking the torque of the pothead bolts, and (4) Explain the instrumentation including any alarms provided to monitor the oil levels for the cable system. Also, provide details regarding existing surveillance and calibration for these instruments and during the PEO.

RESPONSE
The HNP cables are high-voltage, oil-filled, paper insulated, lead-sheathed cables. The lead sheath is designed to prevent moisture from penetrating the cable and degrading the cables insulation. The HNP cables have an Okolene (black polyethylene) outer jacket. The lead sheath combined with the overall PE jacket has proven to be an effective barrier against moisture. HNP will clarify Table 3.6.2-1, Note 602 in an amendment to the LRA.

The mechanical components that support the oil-filled cable system are evaluated in Sections 2.3.3.81, and Table 3.3.2-69 (page 3.3-426) of the HNP LRA. Currently, the System Engineer performs visual inspections and walkdowns of the oil-filled cable system on a quarterly basis. For the PEO, external visual inspections of the cable systems oil filled tanks will become part of the External Surfaces Monitoring Program as shown in Table 3.3.2-69 (page 3.3-426) of the HNP LRA. The External Surfaces Monitoring Program is described in Section B.2.22 of the HNP LRA. The program includes visual inspections of the oil filled tanks, piping and piping components for items such as, leaking components, seepage, loose bolts or threaded fasteners, and damaged or missing parts.

To preserve the electrical continuity function of the oil-filled cable system during the PEO, a power factor (Doble) test will be performed on the oil-filled cables. This test will measure dielectric losses of the cables insulation to provide an indication of a breakdown of the cables insulation properties. The oil-filled cables are to be tested at least once every four years. This is an adequate period to preclude failures of the conductor insulation since experience has shown that aging degradation is a slow process. A four-year testing interval will provide multiple data points during a 20-year period, which can be used to characterize the degradation rate. The first tests for License Renewal are to be completed prior to the PEO. The elements of this test program will be provided in an aging management program (AMP).

The insulating oil environment of the cable system is documented in Table 3.0-1 (page 3.0-7) of the HNP LRA. Periodic testing of the insulating oil in the cable system is not a vendor recommended activity. This is a closed system, with no moving parts, that should remain closed so as not to introduce contaminants. This activity would be performed as a corrective action based on the results of power factor testing. Corrective actions such as testing the insulating oil will be

implemented through the HNP Corrective Action Program. The Corrective Action Program is implemented by the HNP QA Program in accordance with 10 CFR 50, Appendix B.

System leakage discovered during conduct of the External Surfaces Monitoring Program would warrant the need for corrective actions during the PEO. Corrective actions such as checking the torque of the pothead bolts and/or repairing leaking fittings will be implemented through the HNP Corrective Action Program. The cable system oil-filled tanks are equipped with high-low pressure switches that are calibrated every other outage by the Transmission Dept under Interface Agreement with the site. The pressure switches provide annunciation on a common alarm panel in the Relay Building located in the 230KV Switchyard and reflash in the Energy Control Center. The Energy Control Center calls the HNP control room directly should they receive an alarm. The HNP control room would, in turn, dispatch an outside Auxiliary Operator, and call the site Plant Transmission Activities Coordinator (PTAC) to investigate the nature of the alarm.

A License Renewal Application amendment is required.

STAFF EVALUATION
The staff finds the applicant's response acceptable because the applicant has committed to develop an aging management program to address the electrical continuity function of the oil-filled cable system during the PEO. The applicant proposes a power factor test at least once every four years that will measure the dielectric losses of the cable insulation to provide an indication of a breakdown of the cables' insulation properties. The first tests will be completed prior to the PEO. The staff determined that the test data will provide multiple data points during a 20-year period which can be used to characterize the degradation rate. If any degradation is noted, the applicant will confirm it through insulating oil analysis and other tests in accordance with the HNP Corrective Action Program. In addition, the staff noted that, to manage the aging effects of mechanical portion of the oil-filled cable system, the applicant uses its External Surfaces Monitoring Program to conduct visual inspections of the oil filled tanks, piping and piping components for items such as, leaking components, seepage, loose bolts or threaded fasteners, and damaged or missing parts. The System Engineer also performs visual inspections and walkdowns of the oil-filled cable system on a quarterly basis to identify any potential degradation in the system. The cable system oil-filled tanks are equipped with high-low pressure switches that are calibrated every other outage by the Transmission Dept under Interface Agreement with the site to identify for potential loss of pressure in the oil tanks. The projected team determined that the applicant has adequately addressed the aging management of the oil filled cable system. This question is resolved.

LRA Section 4.1- Identification of Time Limited Aging Analyses
Question No. 4.1-1 (SG Flow-Induced Vibration and Wear)

Request
The HNP Model delta 75 RSGs were analyzed at uprated power conditions for flow-induced vibration and wear. Table 4.1-2 of the LRA does not identify this as a TLAA. Explain why flow-induced vibration (FVI) was not identified as a potential TLAA. Also, provide the basis the power uprate FVI and wear analyses remain valid for the period of extended operation.

HNP Response:
The time-dependent assumptions used in the flow-induced vibration calculation are based on a 40-year design life for the steam generators. The replacement steam generators were installed in 2001 and their design life, which extends to 2041, surpasses the current operating period. Therefore, criterion (3) of 10 CFR 54.3 (Involve time-limited assumptions defined by the current operating term, for example, 40 years) is not met. Loss of material for the steam generator tubes is managed by a combination of the Steam Generator Tube Integrity and the Water Chemistry Programs (See Table 3.1.1, Item Number 3.1.1-72, Page 3.1-34 of the LRA).

Staff Evaluation:
The flow-induced vibration may cause tube fatigue cracking. The steam generator tube integrity now depends on managing aging effects by Steam Generator Tube Integrity Program. The staff reviewed steam generator tube integrity program and documented in Section 3.0 of this SER. The staff agrees that tube fatigue analysis is no longer the basis of the safety determination. Therefore, the staff agrees that steam generator tube fatigue analysis is not a TLAA..

Section 4.1- Identification of Time Limited Aging Analyses
Question No. 4.1-2 (RCP Flywheel Evaluation)

Request
NUREG-1800, Table 4.1-3 identifies the fatigue analysis of the reactor coolant pump flywheel as a potential TLAA. Table 4.1-2 of the LRA indicates that the fatigue analysis of the reactor coolant pump flywheel did not meet the TLAA criteria. Provide the basis for this statement.

HNP Response:
The evaluation prepared to support the inspection interval for inservice inspections of the reactor coolant pump flywheels is based on a plant life to be 60 years. Therefore, criterion (3) of 10 CFR 54.3 (Involve time-limited assumptions defined by the current operating term, for example, 40 years) is not met.
During discussions of the initial response to this question, the NRC staff requested information regarding the current inspection regimen for the RCP flywheels. This information is provided below. Plant Technical Specification Amendment No. 119, Section 4.4.10, states:

> Each Reactor Coolant Pump Motor Flywheel be inspected per the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August, 1975. In lieu of Position C.4.b(1) and C.4.b(2), a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals. These inspection requirements are captured in the current Inservice Inspection Program Plan.

Staff Evaluation:
The staff reviewed the applicant's response. On the basis of this fatigue crack growth (FCG) evaluation was prepared to support the inspection interval for ISI instead of the current operating term (40 years), the staff agreed that the RCP flywheel FCG analysis does not meet 10 CFR54.3 requirement for TLAA. Additional, the plant technical specification amendment provided evidence to support the inspection requirement for the component.

Section 4.3 Metal Fatigue
Question 4.3-1 (NSSS Transient Cycle Projections for 60-year Operation)

Request
Explain the following differences between Table 4.3-1 of LRA (NSSS Transient Cycle Projections for 60-year Operation) and Table 3.9-1 of UFSAR (Summary of Limiting Reactor Coolant System Design Transients):

- LRA Normal Transients No.13 and 14 are not in UFSAR Table 3.9-1
- UFSAR Transient No. 5b (Inadvertent Auxiliary Spray Cooling) is not in LRA Table 4.3-1
- LRA Upset Transient 8 (Inadvertent Startup of an Inactive Loop) is not in the UFSAR Table 3.9-1
- LRA Test Transients are not the same as UFSAR Table 3.9-1

HNP Response:

1. LRA Transients No. 13 and 14 were introduced by WCAP-14778 (see Item Number 2 of LRA 4.3-16)
2. The inadvertent auxiliary spray transient is a sub category of the umbrella transient Inadvertent RCS Depressurization. The Inadvertent RCS Depressurization has 20 cycles with 10 of those cycles being the postulated as inadvertent auxiliary spray events. The inadvertent auxiliary spray events were not specifically listed, since the inadvertent auxiliary spray events were already included in the Inadvertent RCS Depressurization transients.
3. The inadvertent startup of an inactive loop was introduced in WCAP-14778 (see Item Number 2 of LRA 4.3-16)
4. The test transients in Table 4.3-1 of the LRA and FSAR Table 3.9-1 are the same but are listed in different locations. Please use the table that is provide on the next page for reference:

Harris Nuclear Plant License Renewal Audit Question and Response Database

Transient	LRA Table 4.3-1 (page 4.3-22)	FSAR Table 3.9.1-1
Primary Side Hydrostatic Test	Test Transient 1	Test Condition 1
Secondary Side Hydrostatic Test	Test Transient 2	Test Condition 2
Primary Side Leak Test	Test Transient 3	Normal Condition 11
Secondary Side Leak Test	Test Transient 4	Normal Condition 12
Steam Generator Tube Leak Test	Test Transient 5	Test Condition 3

Staff Evaluation:
The staff finds the applicants response to be acceptable based on the following basis:

(1) The applicant's response in question 4.3-16 states that Normal Transients 13, 14, and Upset Transient 8 were included in the qualifications performed by WCAP-14778,Revision 1, "Carolina Power and Light Harris Nuclear Plant Steam Generator Replacement/Uprating Analysis and Licensing Project NSSS Engineering Report", September 2000. As noted in the license renewal basis document, "Normal Condition" transients 13 and 14 ("Loop Out of Service") are not applicable to the current HNP license. HNP is not currently licensed to operate with N-1 loops. The "Loop Out of Service" transients were included in the Westinghouse System Standard Design Criteria (SSDC 1.3, Rev. 2) so that the components are designed in case the plant is licensed to operate with N-1 loops. It was recommended by Westinghouse that the "Loop Out of Service" transients continue to be considered for the SGR/Uprating Project. Therefore, the transients were carried forward to the License Renewal fatigue evaluation. On the basis of that considering additional transients in the fatigue analysis will generate a conservative result, the staff finds this acceptable.

(2) The staff reviewed the transient definition and confirmed that the inadvertent auxiliary spray transient is a sub category of the umbrella transient Inadvertent RCS Depressurization. On this basis, the staff find this acceptable.

(3) The staff reviewed the comparison table and confirmed that the applicant did include all test conditions as listed in FSAR Table 3.9.1-1.

Section 4.3 Metal Fatigue
Question 4.3-2 (60 Year Projected Cycles)

Request
Describe the method used to estimate the number of cycles for 60 years operation for the following transients listed in LRA Table 4.3-1:

- Normal Transient No. 10 (feedwater cycling)
- Upset Transient No.12 transient (RCS cold over-pressurization)

HNP Response:
The cycle projections will be removed from the License Renewal Application. Cycle projections will not be used to justify acceptability of fatigue-related TLAAs by 10 CFR 54.21(c)(1)(i) - the analyses remain valid for the period of extended operation. The general deletion of cycle projections from the License Renewal Application affects the response to the following questions:

– Question No. 4.3-3
– Question No. 4.3-4
– Question No. 4.3-5
– Question No. 4.3-10
– Question No. 4.3–16

The response to those questions will reference the response to this question concerning this issue. A License Renewal Application amendment is required (to revise Table 4.3-1 and various subsections of Section 4.3 that used the cycle projection discussion on page 4.3-2 of the LRA as a qualification basis).

Staff Evaluation:
On the basis of that Cycle projections will not be used to justify acceptability of fatigue-related TLAAs by 10 CFR 54.21(c)(1)(i) - the analyses remain valid for the period of extended operation and the applicant's LRA amendment to delete cycle projections from the LRA, the staff finds this acceptable.

Section 4.3 Metal Fatigue
Question No: LRA 4.3-3

Request
Table 4.3-2 (Design Fatigue Usage Factors) of the LRA indicates that the design fatigue usage factor for core internals is 0.52. Section 4.3.1.2 also states that, "Forty-year design CUF values were also determined as part of the HNP SG replacement/uprating analysis." Clarify whether the current licensing basis (CLB) for the 60-years fatigue evaluation of the reactor internals is based on the original design analysis or the SG replacement/uprating analysis.

HNP Response
The 60-year fatigue evaluation for license renewal was done by WCAP-16353-P, Harris Nuclear Plant Fatigue Evaluation for License Renewal. This evaluation relies in part on previous evaluations including the HNP steam generator replacement/uprating analysis. The CLB for 40-years of operation is based on a design usage factor of 0.52 for the reactor core internals. This is based on the HNP steam generator replacement/uprating report which identifies the design usage factor of 0.52 for the reactor internals (for 40 years of operations). Multiplying this 40-year fatigue usage of 0.52 by 1.5 to account for 60 years of operation yields a CUF of 0.78 which does not exceed the design limit of 1.0. Therefore, the analysis has been projected to the period of extended operation using 10 CFR 54.21(c)(1) method (ii). Since this evaluation no longer relies on cycle projections, the LRA requires revision. The general deletion of cycle projections as a qualification basis for fatigue-related TLAAs is addressed in the response to LRA 4.3-2. A License Renewal Application amendment is required.

Staff Evaluation:
The staff reviewed the applicant's basis document WCAP-16353-P and confirmed the core internal CUF of 0.52 for the 40 years operation. The staff accepted that 60 years CUF of 0.78 was projected by multiplying this 40-year CUF of 0.52 by 1.5 and meet 10 CFR 54.21(c0(1)(ii).

Section 4.3 Metal Fatigue
Question No. 4.3.1.6-1 (Pressurizer Fatigue Analysis)

Request
LRA section 4.3.1.6 states, "Certain locations of the pressurizer lower head are not bounded by the original design fatigue analysis" and "Recommendations of the Westinghouse Owners Group (WOG) were used to address operational pressurizer insurge/outsurge effects."

- Discuss the modified operating procedure used to mitigate the pressurizer insurge/outsurge transients.
- Describe how the fatigue usage prior to the use of modified operating procedures was captured in the fatigue evaluation.
- Describe how the estimated 60 year fatigue usage factors for the pressurizer lower head locations and the surge line RCS hot leg location shown in Table 4.3-2 were calculated.

HNP Response:

- Discuss the modified operating procedure used to mitigate the pressurizer insurge/outsurge transients.

The HNP operating procedures for plant startup, normal plant heatup, power operation, normal cooldown and shutdown operations have been modified to include measures to manage insurge/outsurge transients. Westinghouse Owner's Group recommendations provided in WCAP-14950, *Mitigation and Evaluation of Pressurizer Insurge/Outsurge Transients*, were included in the modified operating procedures for these plant operating modes. These recommendations were proceduralized on 01/20/94. Generic operational strategies to mitigate pressurizer insurge/outsurge transients and their effects fall into in two main categories, overall and local. The overall strategies are aimed at establishing conditions during the overall heatup and cooldown procedures that would generally help to prevent or reduce the severity of insurge/outsurge transients. The local strategies focused on particular operations, their effects on transients, and counteracting these effects.

<u>Overall strategies</u>

1. Maintain continuous pressurizer outsurge flow during heatup and cooldown operations
2. Minimize the system ΔT

The first overall strategy helps to decrease the occurrences of insurge transients, keeping flow in the opposite direction and maintaining the lower head at essentially uniform pressurizer saturation conditions. The second reduces the severity of insurge and subsequent outsurge transients if they happen to occur.

Local Strategies

Local strategies deal with controlling RCS coolant mass inventory and temperature. Major areas included control of charging and letdown operations and heat inputs. The major goal in avoiding pressurizer transients during heatup and cooldown is to anticipate particular operations that may cause insurges, and counteract their effects. For other operations that could cause insurges the strategy is to identify those that could cause insurges, and first attempt to revise the procedure so as to avoid the insurge. If the insurge cannot be avoided, then the operation should be performed when the system ΔT is low enough to make the transient insignificant. Details of these and other specific measures taken to mitigate the effects of insurge/outsurge transients are included in the plant operating procedures which are available for review.

- Describe how the fatigue usage prior to modification of the operating procedure was captured in the fatigue evaluation.

WCAP-16376-P, *Evaluation of Pressurizer Insurge/Outsurge Transients for Harris Nuclear Plant*, and WCAP-16353-P, *Harris Nuclear Plant Fatigue Evaluation for License Renewal* contains the evaluation of the components affected by insurge/outsurge transients. Details concerning treatment of pre-Modified Operating Procedure transients and the fatigue evaluations for license renewal are contained therein are available for review.

- Describe how the estimated 60 year fatigue usage factors for the pressurizer lower head locations and the surge

line RCS hot leg location shown in Table 4.3-2 were calculated.
The detailed evaluation of the pressurizer lower head and surge line locations is contained in WCAP-16376-P, *Evaluation of Pressurizer Insurge/Outsurge Transients for Harris Nuclear Plant*, and WCAP-16353-P, *Harris Nuclear Plant Fatigue Evaluation for License Renewal* and are available for review.

Staff Evaluation:
The question is for clarification and information purpose. The applicant's response provided the required information, such as calculation and WCAP reports, for staff's review purpose. The staff reviewed WCAP reports as provided by the applicant's response to confirm that the applicant's response is valid.

Section 4.3 Metal Fatigue
Question No: LRA 4.3.1-1

Request
The basis document (CN-PAFM-04-136 Rev. 0) indicated that cycles up-to-date were evaluated by scaling cycles using the plant data from 7/19/1999 to 10/18/2004 to determine the cycles for early operation years. Please discuss the validity for this backward projection since operating experience has demonstrated that more transient cycles were experienced in early operation of nuclear plants.

HNP Response
Two locations used sample data for the purposes of estimating past and future transient cycles. These were the pressurizer, which included the surge line and pressurizer lower head region, and the charging nozzles. Each was treated in a slightly different manner, which will be discussed below. However, both systems are subject to local thermal transient conditions that are the result of the normal control systems' actions that occur during normal plant operations, such as plant heatup and cooldown operations. These local thermal events, such as the thermal stratification of the pressurizer surge line or the de-stratification of the pressurizer surge line, are too subtle to be tracked in the normal manner that utilizes macroscopic changes in the plant status. These events are generally the result of the normal automatic response of the plant control systems.

The original plant computer systems were never designed to retain all of the information in the resolution necessary for accurate reconstruction of local thermal transients acting on the charging line nozzles and pressurizer lower head and surge line. Therefore, a method of sampling combined with operations interview was employed to estimate the effects of past operations. In some cases, additional information was obtained through the use of direct measurement with temporary sensors attached to the outside of piping system as was the case with the HNP pressurizer surge line. For each of the systems under consideration, the sample observations were correlated with known plant events, which are tracked like plant heatup and cooldown operations.

<u>Pressurizer Surge Line</u>
In the case of the pressurizer surge line, the sample data set was further categorized by what is termed pre-Modified Operating Procedures and Modified Operating Procedures (MOPs), which are employed to reduce the frequency and severity the thermal stratification events in the pressurizer lower head. Data collected from operations prior to implementation of the MOPs was treated separately from the data collected after the implementation of MOPs. In this manner the favorable reduced frequencies associated with the current operating practices are not introduced into the estimates used for past operations, where the MOPs were not employed. This resulted in development of at least two distinct transient sets that were analyzed for the pressurizer lower head and surge line. The data collected was also used to create a conservative set of surge line only events for the period of operation that pre-dated the implementation of the Modified Operating Procedures. The frequency and severity of events observed in the sample sets were then used with the known events to establish the total transients experienced to date.

<u>Charging Nozzles</u>
The charging nozzles experience their worst transients when the plant is at normal operating conditions. Charging events that occur during plant heatups and cooldown experience lower ΔT events because of the lower temperatures of the RCS. Therefore, to address this and considering the impact of the equivalent cycles reduction based on observed ΔT, the total charging cycles were developed using the total number of years of operations times the total number of

equivalent cycles observed in the sample data set. It should be noted that the Modified Operating Procedures do not affect the frequency of charging or letdown isolation events.

Staff Evaluation
The applicant's response indicated that the locations using this approach were related with thermal local events locations such as pressurizer lower head, surge line and charging nozzles which are subjected to thermal stratification transients. Thermal stratification transients were not considered during original design. The applicant used the operation data collected from its plant computer system to determine its frequency and severity. On the basis of that data collected from operations prior to implementation of the MOPs was treated separately from the data collected after the implementation of MOPs, the staff determined that this is acceptable and provided realistic fatigue result for up-to-date usage factor.

Section 4.3 Metal Fatigue
Question No. 4.3.1-3

Request
In the basis document (CN-PAFM-04-128, R0 (page 41)), the applicant applied cycle reduction methodology derived from B.31.1 code to reduce 36 cycles to 1 cycle for ASME CL 1 components. Please provide justification to address ASME Code compliance issue. Note: B.31.1, ASME CL 2 & 3 thermal effects do not consider the temperature rate change as ASME CL 1 component class. ASME Code does not allow class 1 component uses this reduction methodology.

HNP Response
This response is related to the response to Question 4.3-7.

An independent ASME Section III, Division I, Subsection NB fatigue evaluation has been performed in order to establish a quantitative basis for the application of the ANSI B31.1 cycle reduction methodology to cycle counting of the HNP charging nozzle transients. The discussion below summarizes this effort.
A model representative of the HNP charging nozzle, created using the finite element program ANSYS, was evaluated for fatigue using the program WESTEMS™, developed by Westinghouse. The ANSYS finite element model was a 3 dimensional model consisting of a 100-inch section of the RCS Loop piping section including the entire charging nozzle and branch piping for a length of approximately 4 pipe diameters. The model was loaded with mechanical and thermal loadings in a manner consistent with the assumptions used in the original design basis fatigue evaluation. Two sets of transients were created to make the comparison between the reduced equivalent full cycle transient set and the actual observed transient set. To make the comparison and to maintain conservatism, the original design transient temperature time histories and rates were employed with reduced ΔT's. This effectively removed the added effect of lower rates experienced by the actual transients (which would make them even less severe with respect to stress). The result is a conservative representation of the actual events. The tables below summarize the two sets used. Table 1 lists the original design transient cycles, the actual (reduced ΔT) counts, and equivalent full range counts.

Table 1 Charging design transients used to make this comparison

Transient Name	Allowable (Design) Cycles	Enveloped Counts from actual 5.26 years	Equivalent Full Range Cycles
Charging and Letdown Flow Shutoff and Return to Service	36	36	1
Letdown Flow Shutoff with Prompt Return to Service	120	36	4
Letdown Flow Shutoff with Delayed Return to Service	12	9	0
Charging Flow Shutoff with Prompt Return to Service	12	0	0
Charging Flow Shutoff with Delayed Return to Service	12	0	0
Charging Flow Step Decrease and Return to Normal	14400	0	0
Charging Flow Step Increase and Return to Normal	14400	0	0
Letdown Flow Step Decrease and Return to Normal	1200	11	3
Letdown Flow Step Increase and Return to Normal	14400	364	11

Only the flow shutoff transients were considered in this investigation. This is valid due to the low number of observed events of the flow increase/decrease transients, and the fact that the charging and letdown flow step decrease and charging and letdown flow step increase transients do not significantly contribute to fatigue.
After excluding the flow increase/decrease transients, the 81 highest ΔT events observed were used. To reduce the number of transient curves that had to be created, the 81 actual ΔT events were conservatively grouped into the ΔT transient categories shown in Table 2:

Table 2 Actual Charging Transients Analyzed

Transient	Cycles	Temperature ΔT
Charging and Letdown Flow Shutoff and Return to Service	1	433
Charging and Letdown Flow Shutoff and Return to Service	1	333
Charging and Letdown Flow Shutoff and Return to Service	2	247
Charging and Letdown Flow Shutoff and Return to Service	1	207
Charging and Letdown Flow Shutoff and Return to Service	20	120
Charging and Letdown Flow Shutoff and Return to Service	11	33
Letdown Flow Shutoff with Prompt Return to Service	4	360
Letdown Flow Shutoff with Prompt Return to Service	4	340
Letdown Flow Shutoff with Prompt Return to Service	3	320
Letdown Flow Shutoff with Prompt Return to Service	3	290
Letdown Flow Shutoff with Prompt Return to Service	4	250
Letdown Flow Shutoff with Prompt Return to Service	2	175
Letdown Flow Shutoff with Prompt Return to Service	12	115
Letdown Flow Shutoff with Prompt Return to Service	4	20
Letdown Flow Shutoff with Delayed Return to Service	9	112

Table 3 shows the calculated equivalent full design transients and cycles analyzed to make the comparison.

Table 3 Design Transients Analyzed

Transient	Cycles	Temperature ΔT
Charging and Letdown Flow Shutoff and Return to Service	1	460
Letdown Flow Shutoff with Prompt Return to Service	4	460

The equivalent full design transient cycles were determined using the concept provided in Section 102.3.2 of the B31.1 Power Piping Code, which provides a rule for computation of equivalent full temperature cycles of expansion stress when

the range of temperature varies. Per the B31.1 approach, equivalent full temperature cycles are computed as follows:

N = Ne + r1
5 * N1 + r2
5 * N2 + … rn
5 * Nn (Eq. B-1)

Where:

Ne = number of cycles at full temperature change, Te, for which the thermal design stress was calculated
N1, N2, … Nn = number of cycles at lesser temperature changes ΔT1, ΔT2, … Δtn r1, r2, … rn = ΔT1/ΔTe, ΔT2/ΔTe, … ΔTn/ΔTe

The application of this method resulted in the equivalent full cycles listed in Table 1 above. To show the validity of the B31.1 Code application to this component, two detailed fatigue evaluations were performed using the actual cycles in Table 2 and using the 5 cycles of the design transients in Table 3. The expected result is that the fatigue usage factor from the equivalent full design transients will be the same or greater than the fatigue usage from the actual transients. Several locations were investigated using this method. The table shows the results for the limiting locations in the branch piping section (safe end) and the reinforcement region (crotch) of the charging nozzle.

Table 4 Fatigue Usage Comparison

Component	Analysis Section Number	Node	Node Number	Actual Cycles Usage	Equivalent Design Cycles Usage	Equivalent Design - Actual (dU)
212100	1	Inside	1	0.001	0.002	0.00100
212100	1	Outside	11	2.97E-06	9.65E-05	0.00009
212100	2	Inside	1	0.001	0.002	0.00100

212100	2	Outside	11	2.97E-06	9.65E-05	0.00009
212100	3	Inside	1	0.001	0.002	0.00100
212100	3	Outside	11	2.97E-06	9.64E-05	0.00009
212100	4	Inside	1	0.0037	0.0143	0.01060
212100	4	Outside	11	4.51E-06	3.00E-04	0.00030
212100	5	Inside	1	0.0037	0.0141	0.01040
212100	5	Outside	11	4.74E-06	3.00E-04	0.00030
212100	6	Inside	1	0.0036	0.0139	0.01030
212100	6	Outside	11	5.02E-06	3.00E-04	0.00029
212100	7	Inside	1	0.0026	0.011	0.00840
212100	7	Outside	11	0.0011	0.0015	0.00040
212100	8	Inside	1	0.0017	0.0101	0.00840
212100	8	Outside	11	0.0008	0.0011	0.00030
212100	9	Inside	1	0.0019	0.0093	0.00740
212100	9	Outside	11	0.0005	0.0007	0.00020
212100	10	Inside	1	0.0107	0.0276	0.01690
212100	10	Outside	11	6.59E-07	6.99E-07	0.00000
212100	11	Inside	1	0.0069	0.0224	0.01550
212100	11	Outside	11	7.11E-07	7.95E-07	0.00000

The limiting location is ASN 10, inside node, which is a cut located in the reinforcement region of the charging nozzle and RCS loop piping intersection.
The results shown in the table above demonstrate that the use of the equivalent full cycles is conservative, since the equivalent design cycles usage values are all greater than the values obtained using actual cycles.

Staff Evaluation:
On the basis of that the applicant calculation results demonstrated its conservative usage factor, the staff finds this approach is acceptable for this location only.

Section 4.3 Metal Fatigue
Question 4.3.3-1 (Environmentally- Assisted Fatigue Analysis)

Request
Table 4.3-3 provides the 60-year Environmentally-Adjusted CUFs.

- Provide Fen value for each component
- Describe how the 60-year environmentally adjusted CUF and 40-year design CUFs have the same CUF value of 0.173 for RHR Class 1 Piping.

HNP Response:

- Provide Fen value for each component

Table 4.3-3 in the LRA will be revised as follows:

TABLE 4.3-3 60-YEAR ENVIRONMENTALLY-ADJUSTED CUF VALUES

Component	60-Year Environmentally Adjusted CUF (U_{en})	F_{en}	A	B	C
Bottom Head Juncture	0.0491	2.532			
Reactor Vessel Inlet Nozzles	0.0231	2.532			
Reactor Vessel Outlet Nozzles	0.1740	2.532			
Surge Line	2.120 (Note 3)	8.27 (Note 1)	X	X	X
Charging Nozzle	0.89	7.2 (Note 1)	X		X
Safety Injection Nozzle	0.93	5.3 (Note 1)	X		
RHR Class 1 Piping	0.465	2.55 (Note 2)			
Pressurizer (Lower Head at Heater Penetration)	1.35 (Note 4)	2.532	X	X	X

Table Notations and Notes
A. Reduced cycles used in the evaluation
B. Refined calculations performed
C. Redefined transients used in the evaluation

Note 1. The "overall effective Fen" based on evaluation of the fatigue transient pairings. Each transient pair has its own unique Fen.

Note 2. The transients used for the RHR line qualification include only one significant transient defined for "RHR section 2" (RHR section 2 is the section of piping downstream of the isolation valve that is normally at ambient conditions), for RHR initiation when this part of the line goes from ambient conditions to the 350°F RHR letdown temperature. The return phase of the transient is a gradual cooldown with which no appreciable stress is associated. Since the temperature shock for the RHR initiation transient is positive, the stresses on the inside surface of the piping components are compressive. Since the strain rate is compressive, Fen = 1.0 for this controlling condition would be appropriate, based upon the methodology of NUREG/CR-5704. However, a maximum value of 2.55 has been used for the Fen for this evaluation.

Note 3. 40-year design transients were used in the evaluation except for heatups and cooldowns. The number of heatup and cooldown transients used in the analysis is 133 versus 200 original design transients. The fatigue usage for this location based on this transient set is 0.94. Multiplying by 200/133 to account for the full set of design heatups and cooldowns yielded a 40-year fatigue usage of 1.414. Multiplying by 1.5 (that is 60 years/40 years) yields a 60-year fatigue usage of 2.120.

Note 4. 40-year design transients were used in the evaluation except for heatups and cooldowns. The number of heatup and cooldown transients used in the analysis is 133 versus 200 original design transients. The fatigue usage for this location based on this transient set is 0.5984. Multiplying by 200/133 to account for the full set of design heatups and cooldowns yielded a 40-year fatigue usage of 0.9. Multiplying by 1.5 (that is 60 years/40 years) yields a 60-year fatigue usage of 1.35.

- Describe how the 60-year environmentally adjusted CUF and 40-year design CUFs have the same CUF value of 0.173 for RHR Class 1 Piping.

To address the question regarding the effect of the pressure and moment stresses on the total stress and resulting Fen, a detailed time history of the stress during the full RHR transient cycle was developed for the 12" x 1" branch component. The stresses were calculated consistent with the HNP design basis inputs and NB-3600 evaluation methodology. Applicable thermal transient, moment, and pressure histories were applied representing the RHR system design transient in the section of the RHR line containing the branch connection. The transient temperature goes from ambient conditions, at 70°F, to 350°F simulating the initiation of RHR flow through the otherwise isolated section of piping. The design transient description also assumes after the transient that gradual cooling of the system occurs at 100°F/hr, which was considered to represent negligible stress in the design. The RHR flow is initiated by design at approximately 425 psig system pressure. Therefore, a pressure load of 450 psia was used in the calculation. The moment stress from the piping design analysis of the branch was realistically ramped over the transient as a function of the pipe temperature. Pressure and moment stresses were considered only as tensile. The thermal stresses were appropriately signed to represent the inside wall stress in response to the thermal transient. The stresses were adjusted with the branch stress indices

consistent with the Code analysis. The resulting stress history is illustrated in Figure 1 on the next page.

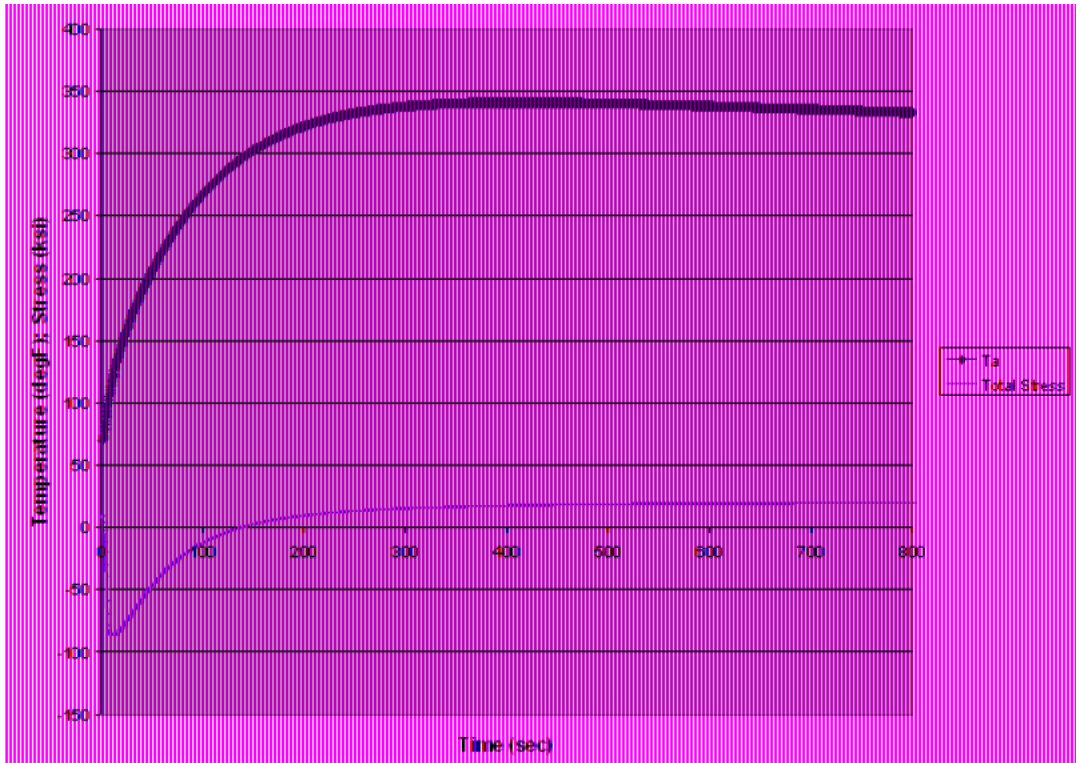

Figure 1 - RHR Transient Temperature and Stress Response for Branch Component

This demonstrates that for the significant part of the transient history, the component is in the compressive state on the inside surface where environmental effects may be applicable. For this reason, in the initial estimation of environmental effects on this component, it was judged that environmental effect would be small and Fen = 1.0 was applied. However, the time history shown does include some periods where stress is in the tensile regime due to the pressure and moment

loads. Therefore, an overall effective Fen was calculated for the entire transient cycle. Strain was determined as the stress divided by elastic modulus (E). The Fen value was calculated by integrating the Fen over the strain history using the modified rate approach (integrating with respect to strain range; methodology discussed in the literature, e.g. reference 1), represented simply by the following equation:

$$Fen = \Sigma (Feni * \Delta\varepsilon i) / \Sigma \Delta\varepsilon i$$

where:

Fen = exp (0.935 - T' ε' O') [see NUREG/CR-5704 for definition of terms], ε= strain

The integration was carried out to the essentially steady-state condition at the end of the transient (around 400 sec). For the beginning portion of the cycle, with a negative strain rate, there is no environmental effect based on NUREG/CR-5704, which states that the environmental effect is only effective in the tensile direction of the cycle. In the second portion of the cycle, with a positive strain rate, the applicable Fen is the threshold value for stainless steel, which is due to the temperature input to the stainless steel Fen equation. The resulting overall integrated value is:

Fen = 1.15

This should be applied to the usage calculated from the stress pair formed from the stress peaks represented by the minimum stress state (maximum compression) and the maximum stress state (maximum tension) of the transient. The total stress range in Figure 1 is approximately 102 ksi. Using the ASME design fatigue curve for stainless steels, this corresponds to approximately 1680 allowable cycles. For 200 design cycles of the RHR transient, the usage factor is 0.12.

Applying Fen = 1.15, Uen = U * Fen = 0.13.

This results in a lower fatigue usage than was conservatively reported from the HNP design evaluation, which reported the 0.173 value, and supports the judgment that for this predominantly compressive cycle that application of Fen = 1.0 to the design usage is adequate.

A conservative alternative is to consider the maximum value of Fen obtained during the entire cycle, which was 2.55, and apply to the usage to obtain Uen = 0.31, which is still acceptable with respect to the ASME allowable of 1.0. Accounting for 60 years of operation by multiplying by 60/40 yields 0.465.

Reference 1: Sakaguchi, Katsumi, et. al., "Applicability of the Modified Rate Approach Method Under Various Conditions Simulating Actual Plant Conditions," PVP2006-ICPVT-11-93220, Proceedings of PVP2006-ICPVT-11, 2006 ASME Pressure Vessels and Piping Division Conference, July 23-27, 2006, Vancouver, BC, Canada.

A License Renewal Application amendment is required.

Staff Evaluation:

The staff reviewed applicant's basis calculation which indicated that the "overall effective Fen" based on evaluation of the fatigue transient pairings and each transient pair has its own unique Fen as stated in Note 1 of this response. On the basis of the applicants fatigue calculation was evaluated by summing the usage factors from each transient pairs multiplying its unique Fen, the staff determine that this meet the original methodology of the N|UREG/CR-5704 and finds this acceptable.

Section 4.3 Metal Fatigue
Question No: LRA 4.3.3-2

Request
Applicant's basis document, "Harris License Renewal Piping Environmental Fatigue Evaluation", (CN-PAFM-04-136, Rev. 0, page 7), stated that Fen = 1.0 for the pair if any one of the following conditions satisfied:

T <= 180°C
ε' > 0.4% / sec
DO => 0.05 ppm
Strain amplitude, <= 0.10%

Please clarify the above statement with its basis since the minimum Fen value should be 2.54 as indicated below. If the statement is not valid, please clarify what impact to the entire calculation.

Note: Fen = exp (0.935 - T' ε' O')

Where T' = 0 (T < 180°C) or any condition would make the second term of the equation equal 0, then Fen = exp (0.935) = 2.54

HNP Response
The wording cited from the text of the calculation is ambiguous and can be misleading about what was actually calculated with respect to the threshold values. The only application of Fen = 1.0 for a threshold limit used in the actual calculations was for a strain amplitude threshold of 0.10%. (For the threshold values of the other parameters, when strain amplitude is > 0.10%, the minimum value of Fen is 2.54.) This is evident upon review of the detailed Fen calculation tables provided in the document. The strain amplitude threshold was based on the NUREGs as discussed below.

The value of Fen = 1.0 is used in the calculations to represent the condition where the environmental effect is insignificant as stated in NUREG/CR-5704, and clarified in NUREG/CR-6717. In these cases, these documents state that no additional environmental penalty is required beyond the factors included in the ASME design fatigue curve. This was based on the statements in the NUREGs noted below:

In Section 6 of NUREG/CR-5704, it states: "the existing fatigue data indicate a threshold strain range of ≈0.32%, below which environmental effects on the fatigue life of austenitic SSs either do not occur or are insignificant. … Thus a threshold strain amplitude of 0.097% (stress amplitude of 189 MPa) was selected, below which environmental effects on life are modest and are represented by the design curve for temperatures <200°C…" NUREG/CR-6717 provides further study of the ANL data and results presented in NUREG/CR-5704, and reiterates the strain amplitude threshold for stainless steels in section 5.3: "The strain threshold is represented by a ramp, i.e., a lower strain amplitude below which environmental effects are insignificant, a slightly higher strain amplitude above which environmental effects are significant, and a ramp between the two values… The two strain amplitudes are … 0.10 and 0.11% for austenitic SSs…" The lower strain amplitude value of 0.10% is a consistent rounded value from the 0.097% value discussed in NUREG/CR-5704.

NUREG/CR-6909 for new plant applications also continues to reiterate the strain amplitude threshold for stainless steels in Appendix A: "For wrought and cast austenitic stainless steels, a threshold value of 0.10% for strain amplitude (one-half the strain range for the cycle) is defined, below which environmental effects on the fatigue life of these steels do not occur. Thus, Fen,nom =1 ($\epsilon a \leq 0.10\%$)." Based on the statements in NUREG/CR-5704 and NUREG/CR-6717, as well as the confirmation of the application provided in NUREG/CR-6909, when the strain amplitude for a fatigue pair was below 0.10%, no additional Fen penalty was applied to the pair. This is effected numerically in the calculations by setting Fen = 1.0. In CN-PAFM-04-136, this is reflected in tables calculating Fen (e.g., Table 6-8) for fatigue pairs with alternating stress (Sa) less than 28.3 ksi, which corresponds to 0.10% strain amplitude for this case.

Staff Evaluation:
The staff reviewed NUREG/CR-5704, 6909 and 6717 to confirm that the equation for Fen will be applied if the threshold limit is exceeded. For the case mention above, the staff confirmed that no fatigue penalty due to environmental effects is required.

Section 4.3 Metal Fatigue
Question 4.3.4-1 (RCS Loop Piping LBB Analysis)

Request
LRA Section 4.3.4 indicates that a new LBB calculation applicable to HNP large bore RCS piping and components was performed and documented in WCAP-14549-P, Addendum 1. Provide the following information regarding the LBB calculation:

- LRA Section 4.3.4 states, "However, the calculations for Alloy 82/182 locations were performed, and this material is not bounding." Explain the basis for this statement.
- LRA Section 4.3.4 states," Ample margin exists in stability using the 60 year, the end of life thermal aging material properties." Discuss the acceptance criteria used for the evaluation and quantify the margin.
- The LRA states that "SCC is precluded," please clarify.
- Please clarify why the A82/182 material is not bounding in the evaluation.

HNP Response
Plant-specific calculations were performed (WCAP-14549-P, Addendum 1, *Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for the Harris Nuclear Plant for the License Renewal Program*) to account for PWSCC crack morphology in that a conservative factor between fatigue cracking and PWSCC was used. When the EPRI MRP methodology described in MRP-140, *Materials Reliability Program: Leak-Before-Break Evaluation for PWR Alloy 82/182 Welds*, has been reviewed and approved by the NRC. HNP will review its plant-specific calculation for conformance to the endorsed approach. Bullet 6 is not required and will be deleted.

In the context of the discussion of Bullet 1 on page 4.3-15 of the LRA, SCC is precluded for the materials other than A82/182. PWSCC of the A82/182 material has been accounted for in the plant-specific calculation (WCAPHNP-14549-P, Addendum 1) performed for License Renewal. The A82/182 material is not bounding because the flaw sizes yielding a leak rate of 10 gpm were larger than those calculated at other locations that do not contain A82/182 material. As stated in the response to Bullet 1 above, HNP will review its plant-specific calculation for conformance with the endorsed approach.

A License Renewal Application amendment is required.

Staff Evaluation
The alloy 600 PWSCC is CLB issue, On the basis of that the applicant will follow the CLB requirement as stated, the staff finds this acceptable for the ist bullet and 4 th bullet. 2nd Bullet; The staff reviewed the applicant's basis document WCAP-14549-P which provide the detail evaluation and acceptance criteria as stated in Section 3.6.3 of SRP(NUREG-800). The staff finds this acceptable. The 3rd bullet is for clarification only.

Section 4.3 Metal Fatigue
Question No: LRA 4.3.3-3

Request
During review the basis documentation of fatigue evaluation, the original transients were used in the analysis and did not mention the fatigue cycling related to Bulletin 88-08. Please explain how Bulletin 88-08 was addressed in the metal fatigue.

HNP Response
Fatigue cycling related to Bulletin 88-08 is managed by procedure titled, *SI Thermal Stratification Monitoring Program*. This program was implemented in response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," which requested that all LWR licensees review any unisolable piping connected to the RCS which may be subjected to unacceptable thermal stresses caused by thermal stratification. The Bulletin further called for licensees to "take action, where such piping is identified, to ensure that the piping will not be subjected to unacceptable thermal stresses. Guidelines for evaluating the effectiveness of the Thermal Stratification Monitoring Program were established by the NRC in a follow-up letter dated September 16, 1991. The guidelines provide evaluation criteria for licensee responses to NRC Bulletin 88-08, Action 3, and Supplement 3. Four acceptable actions were presented by the NRC. Of these, HNP chose option 3 which was to install temperature instrumentation to monitor pipe temperature gradients due to containment isolation valve leakage. HNP has identified High Head Safety Injection Cold and Hot Legs, Normal Charging, and Alternate Charging lines as being susceptible to thermal stratification. Thermocouples were installed at the following check valve locations: 1SI-81, 1SI-82, 1SI-83, 1SI- 136, 1SI-137, 1SI-138, 1CS-486, and 1CS-500. The thermocouples measure the top and bottom pipe temperatures immediately downstream to each check valve.

The Reactor Coolant Pressure Boundary Fatigue Monitoring Program addresses the possibility of fatigue cracking due to thermal stresses caused by thermal stratification in the safety injection, normal charging, and alternate charging lines if certain thermal limits, identified by this procedure, are exceeded. Per the current plant procedure, the temperature time-histories are evaluated by the Responsible Engineer for the following conditions:

Average top-to-bottom temperature differences exceed 100°F.
Top and bottom temperature time histories become significantly out of phase.
Bottom temperature oscillations exceed 50°F peak to peak.
External leakage is detected in closed isolation valves.

The screening criterion of a 100°F average top-to-bottom temperature difference was chosen because HNP performed a plant-specific analysis that demonstrated that the resulting loads and stresses will not threaten the ability of the piping systems to operate safely. Since HNP monitors these lines to ensure that the piping will not be subjected to unacceptable thermal stresses, fatigue cycling related to Bulletin 88-08 did not need to be incorporated in the basis documents.

Staff Evaluation:
The staff reviewed the applicant's operating plant procedure, SI Thermal Stratification Monitoring Program, which was used to manage fatigue cycling related to Bulletin 88-08. The staff confirmed that the applicant's thermal stratification monitoring program monitoring these lines to ensure that the piping will not be subjected to unacceptable thermal fatigue related to Bulletin 88-08. On this basis, the staff finds this acceptable.

Section 4.3 Metal Fatigue
Question No. 4.3.5-1

NRC Request
LRA 4.3.5-1 states "For the purposes of this evaluation, a penetration isolation lasting for more than 10 minutes while the RCS hot leg temperature exceeds 500F is conservatively considered one thermal cycle. Please provide the basis for why transient has to last more than 10 minutes to be considered one thermal cycle. What is HNP's RCS sampling interval? Is it cycled every time sampling piping is used to sample the RCS liquid?

HNP Response
The subject TLAA tubing lines are not cycled every time sampling piping is used to sample the RCS liquid. Therefore, HNP's RCS sampling interval has no influence on cycle counting. This TLAA is associated with the safety related portion of the sample system, which extends from the RCS hot legs in the Reactor Containment Building to the normally open outboard isolation valve in the Reactor Auxiliary Building. License Renewal Scoping Drawing, Attachment 15 (5-G-0052-LR) of the basis document shows this configuration. There is continuous flow through penetration M78A during reactor startup, power operation and shutdown. The RCS coolant continuously flows to the Gross Failed Fuel Detector (GFFD). The GFFD is located downstream of the penetration in the non-safety related portion of the system and outside the boundary of the TLAA. The source of coolant for the Primary Sample Panel (shown on the scoping drawing), which samples RCS coolant, taps off the tubing line between the outboard isolation valve and the GFFD. RCS flow through the safety related portion of the sample system is not interrupted when the primary sample panel is used. Consequently, operation of the sample panel has no influence on thermal cycles. The current methodology considered one cycle as an interruption of a continuous supply of hot RCS coolant through penetration M78A for more than 10 minutes. The HNP methodology has been changed to consider an interruption of primary coolant flow for more than 5 minutes as one cycle. In 5 minutes the temperature of the primary sample system tubing was conservatively estimated to decrease less than 200°F. Appendix H, Section 4.1.1 of the EPRI Report TR-1003056, Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, Revision 4, discusses the basis for the 270°F system screening criterion for fatigue in stainless steel. This temperature value was chosen as a temperature change in components of more than 200°F is not anticipated in these systems. Consequently, 200°F was chosen as a thermal cycle in the primary sample system.

A review of the original data trends was performed using 5 minute closure times. This review resulted in counting an additional 8 cycles; changing 22 cycles in the original analysis to 30 cycles. The projected increase over 60 years is an additional 72 cycles. The total number of cycles for the primary sampling system is then increased from 1279 cycles to 1351 cycles. The overall conclusion remains the same as the number of thermal cycles remains far below the criterion where stress range reduction factors would have to be reduced below unity for fatigue i.e. 7,000 cycles.

A License Renewal Application amendment is required.

Staff Evaluation”
The applicant provided its methodology to define the thermal cycles as above mentioned. The applicant states that the current methodology considered one cycle as an interruption of a continuous supply of hot RCS coolant through penetration M78A for more than 10 minutes. The HNP methodology has been changed to consider an interruption of primary coolant flow for more than 5 minutes as one cycle. In 5 minutes the temperature of the primary sample system tubing was conservatively estimated to decrease less than 200°F. On the basis of the 270°F was used as the current screen criteria for the fatigue consideration, the staff

finds this approach to determine the thermal cycle is acceptable. The increase due to this change will not make the thermal cycle greater than 7000 cycles allowable. On this basis, the staff finds this CUF still valid.

Section 4.3 Metal Fatigue
Question No. 4.3-4

Request
In Section 4.3.1 of the LRA, there is a discussion of the extrapolation methodology for cycle projections. Please justify the validity of the method in projecting various transient cycles to the end of the extended period of operation.

HNP Response
For our purposes we have chosen to use linear extrapolation of the average observed frequency to estimate the total cycles for 60 years of operations. This is deemed acceptable for four reasons:

1) The use of typical trend analysis tools like linear regression using least squares curve fitting would yield unrealistic results due to the reduced frequencies of unplanned events like reactor trips in the most recent data. These methods result in trends with negative slopes that fail to account for the normal planned operational cycles.

2) Use of the average of the observed events extrapolated out through the extended operational life yields non-zero numbers for future events and conservatively introduces higher rates than one would predict using traditional trend analysis methods.

3) The cycles predicted by linear extrapolation yield higher numbers of plant heatup and cooldown events than one would get if fuel cycle durations only were used.

4) A transient and fatigue cycle monitoring will be employed to insure that adequate margins exist between the actual cycles and the design cycles.

However, the discussion of cycle projections will be removed from the License Renewal Application and the individual evaluations in Section 4.3 will be updated accordingly. The column labeled "60 Year Projected Cycles" will be removed from Table 4.3-1. The general deletion of cycle projections as a qualification basis for fatigue-related TLAAs is addressed in the response to LRA 4.3-2.

A License Renewal Application amendment is required.

Staff Evaluation:
On the basis of the cycle projection will be removed from LRA and the design basis cycles are not changed, the staff finds this acceptable.

Section 4.3 Metal Fatigue
Question No. 4.3-5

NRC Request:
In Section 4.3.1 of the LRA (page 4.3-2, third paragraph), there is a discussion on the comparison of the 60-year cycle projections and its comparison to 40-year design cycles. Please clarify why it is appropriate to use 60-year projection to determine the adequacy of the current fatigue analyses based on 40 years. Please clarify whether (or how) the projected cycles are used in developing Tables 4.3-2 and 4.3-3.

HNP Response:
1. The use of the 60 years cycles projections shows that the existing design frequencies are conservative and therefore still valid even after 60 years of operations. This statement remains true as long as the 60 years projected cycles are less than or equal to the current design frequencies.

2. In general, design numbers of cycles were used for fatigue calculations whose results are presented in Table 4.3-2. The exceptions to this are provided in Notes 1 and 2 to Table 4.3-2; specific Steam Generator sub-components, the Pressurizer lower head, and pressurizer surge line were re-qualified based on the projected cycles. In Table 4.3-3, the results for the surge line, charging nozzle, safety injection nozzle and pressurizer lower head used projected cycles. More information on these locations is provided in the response to question LRA 4.3.3-1. An online stress and fatigue cycle monitoring system has been installed to maintain continuous surveillance of the operational fatigue damage accumulation rate for the pressurizer lower head and surge line. However, the discussion of cycle projections will be removed from the License Renewal Application and the individual evaluations in Section 4.3 will be updated accordingly. The column labeled "60 Year Projected Cycles" will be removed from Table 4.3-1.

The general deletion of cycle projections as a qualification basis for fatigue-related TLAAs is addressed in the response to LRA 4.3-2.

A License Renewal Application amendment is required.

Staff Evaluation
The basis for acceptance in the staff's evaluation of Question No. 4.3-4 is applicable to the staff's evaluation of Question No. 4.3-5. Refer to staff's evaluation of Question No. 4.3-4.

Section 4.3 Metal Fatigue
Question No. 4.3-6

Request
In Section 4.3.1 of the LRA (page 4.3-2, first paragraph), there is a discussion of pressurizer surge line analyses. Please provide the chronology for the qualification of the surge line beginning with IE Bulletin 88-11 through License Renewal.

HNP Response
In September 1991, WCAP-12962, *Structural Evaluation of the H. B. Robinson Unit 2 and Shearon Harris Pressurizer Surge Lines, Considering the Effects of Thermal Stratification* was issued. This report was prepared to demonstrate compliance with the requirements of NRC Bulletin 88-11 for H. B. Robinson Unit 2 and Shearon Harris. Prior to the issuance of the bulletin, the Westinghouse Owners Group had a program in place to investigate the issue and to recommend actions by member utilities. That program provided the technical basis for the analysis in WCAP-12962 for H. B. Robinson Unit 2 and Shearon Harris.

As part of the Steam Generator Replacement/Power Uprate (SGR/PU) project, a reanalysis was performed by Westinghouse (CN-SMT-99-66) that evaluated the effects of steam generator replacement, the revised center of gravity of the steam generator, and the power uprate. This calculation was incorporated as an addendum to HNP calculation 3043W. The results of this analysis were captured in WCAP-15398, *Carolina Power and Light Harris Nuclear Plant Steam Generator Replacement/Uprating Analysis and Licensing Project NSSS Licensing Report* in Section 5.5.3, Class 1 Auxiliary Lines. WCAP-15398 was included as Enclosure 8 to HNP letter Serial: HNP-00-142, *Shearon Harris Nuclear Power Plant, Steam Generator Replacement, Technical Specification Amendment Application, Docket NO. 50-400, License No. NPF-63*, October 4, 2000.

As part of the license renewal effort, WCAP-16376-P, *Evaluation of Pressurizer Insurge/Outsurge Transients for Harris Nuclear Plant* was prepared. This report describes the development of plant-specific pressurizer insurge/outsurge and surge line stratification transients, and the evaluation of fatigue usage for the pressurizer lower head and surge line RCS hot leg nozzle for 60 years of predicted plant operation. Finally, the 60-year surge line environmental fatigue usage was determined in WCAP-16353-P, *Harris Nuclear Plant Fatigue Evaluation for License Renewal*.

Staff Evaluation
This question is for clarification and information only. The staff used this information to locate the related basis documents.

Section 4.3 Metal Fatigue
Question No. 4.3-7

Request
In Section 4.3.1 of the LRA (page 4.3-2), there is a discussion of partial cycle counting using the methodology described in ANSI B31.1 Power Piping Code, 1967 Edition, Section 102.3.2. Is this methodology applicable to Class 1 piping? Is this methodology applicable to Class 1 components other than piping? Where was this methodology used?

HNP Response

1. The methodology is not applicable to ASME Section III Class 1 piping. In the response to LRA 4.3.1-3, HNP provided a technical evaluation comparing the results from an independent ASME Section III, Division I, Subsection NB fatigue evaluation against the application of the ANSI B31.1 cycle reduction methodology to show that it was reasonable to use in the specific case of the charging nozzles.

2. The applicability of this methodology to other than piping components was not investigated, as it was not used for components other than piping.

3. This methodology was used to determine equivalent numbers of full design transient cycles on the charging nozzles.

See response to Question No. 4.3.1-3 for supporting information as to the appropriateness of using this methodology for ASME Section III Class 1 piping.

Staff Evaluation
The methodology was only applied to charging nozzles and the staff's basis acceptance was evaluated and provided in the staff evaluation of Question No. 4.3.1-3.

Section 4.3 Metal Fatigue
Question No. 4.3-8

Request
For the evaluations performed for Class 1 components in Section 4.3 of the LRA, please provide the following information:

What is the original Code of Record?
If so, what is the latest edition?

HNP Response:
Original Codes of Record are provided in the HNP FSAR Table 5.2.1-1 (below). The latest edition that was used for Class 1 equipment analysis is taken from WCAP-15399, "Carolina Power and Light Harris Nuclear Plant Steam Generator Replacement/Uprating Analysis and Licensing Project, NSSS Licensing Report," September 2000 (Westinghouse Non-Proprietary Class 3).

SHNPP FSAR TABLE 5.2.1-1 APPLICABLE CODE ADDENDA FOR RCPB COMPONENTS			WCAP-15399
Component	Required by 10CFR 50.55a	Designed and Fabricated	
Reactor vessel	Summer 1972	Winter 1971	1971 Edition with Addenda through Winter 1971
Full Length CRDM	Summer 1972	Summer 1974	1974 Edition with Addenda through Summer 1974
CRDM Head Adapter plugs	Summer 1972	Winter 1976	1974 Edition with Addenda through Winter 1976
Reactor Coolant Pump	Winter 1972	Summer 1972	1971 Edition with Addenda through Summer 1972

Replacement Steam Generator	Summer 1972	Summer 1972 (Design)* 1986 Edition (Fabrication)	1971 Edition, Summer 1972 Addendum, Material strength from Summer 1972 Addendum to 1971 Edition. Where not available, material strength from 1986 Edition
Pressurizer	Summer 1972	Summer 1972	1971 Edition through Summer 1972 Addenda
Reactor coolant loop pipe	Winter 1972	Summer 1973	Section III (NB) through the Winter 1979 Addenda
Connecting Systems piping	Winter 1972	Summer 1973	(Class 1 auxiliary Lines) Subsection NB and NC 1977 Edition and addenda through Summer 1979 **

* 1986 Code Edition is applicable for materials not available in the Summer 1972 Code.
** Note: S-N curves from the 1986 Code Edition were used in the surge line stratification analysis.

Staff Evaluation
The question is for information and clarification purpose. The staff reviewed the applicant's information to confirm the applicant used the valid code.

Section 4.3 Metal Fatigue
Question No. 4.3-9

Request
In Section 4.3.1.5 (page 4.3-7), there is a discussion of "replacement schedule" for certain secondary side steam generator bolting. Has this bolting ever been replaced? Note 1 of Table 4.3-2 also needs to be clarified.

HNP Response

– *Has the bolting ever been replaced?*
Bolting for the steam generators has been replaced but not in accordance with any replacement schedule that would be associated with fatigue. Stud replacements were performed in 2001, 2003, and 2004 on secondary manways.

– *Note 1 of Table 4.3-2 needs to be clarified.*
Note 1 of Table 4.3-2 will be modified as follows (additional text is shown in italics):
Due to the original design usage factors exceeding 1.0, these bolts were originally *to be* replaced based on a replacement schedule, however, these fatigue usage values have been superseded by the results of the license renewal fatigue evaluation described in Subsection 4.3.1.5 *and a replacement schedule is no longer required*. As stated in the response to B.3.1-RH-01, the updated evaluation changed only the number of Unit Loading and Unit Unloading transient cycles relative to the previous design analysis. The HNP Fatigue Management Program will be enhanced to track these cycles with a limit of 2000 cycles and an alarm limit of 1500 cycles.

A License Renewal Application amendment is required.

Staff Evaluation
This question is for clarification only. The applicant provided its LRA amendment to address this item. The staff reviewed the basis document and confirmed that the bolt replacement schedule is no longer required.

Section 4.3 Metal Fatigue
Question No. 4.3-10

Request
In Section 4.3.1.6 (page 4.3-9) of the LRA, please explain whether design cycles or projected cycles were used in the 60-year fatigue evaluation.

HNP Response
(This response is the same as Item Number 2 in Question 4.3-5) Section 4.3.1.6 of the HNP LRA provides the evaluation of fatigue-related pressurizer TLAAs. In general, the projected cycles were not used for design fatigue calculations. There are two exceptions; however, the Pressurizer lower head and pressurizer surge line were re-qualified based on the projected cycles. An online stress and fatigue cycle monitoring system has been installed to maintain continuous surveillance of the operational fatigue damage accumulation rate.

The general deletion of cycle projections as a qualification basis for fatigue-related TLAAs is addressed in the response to Question No. 4.3-2. Also, refer to the response to Question 4.3.3-1.

Staff Evaluation
The basis for acceptance in the staff's evaluation of Question No. 4.3.3-1 is applicable to the staff' evaluation of this question. Refer to the staff's evaluation of Question No. 4.3.3-1.

Section 4.3 Metal Fatigue
Question No. 4.3-11

Request
In Section 4.3.1.6 (page 4.3-9), there is a discussion of the 60-year fatigue evaluation for the pressurizer components including the surge line.
Has the RCS piping specification ever been updated and re-certified?

HNP Response
The D-Spec, *Piping Design Specification, ANS Safety Class 1 - RCS, SIS, RHRS, CVCS, RVHVS, RVLIS*, was updated to Revision 3 in 1986 and re-certified at that time. Revision 3 eliminated AIB (arbitrary intermediate breaks) and added LBB (leak-before-break) criteria, allowed use of PVRC (Pressure Vessel Research Committee) damping, allowed use of Westinghouse SSDC 1.3X thermal transients, and updated allowable acceleration for valves. Per WCAP-15398, *Carolina Power and Light, Harris Nuclear Plant, Steam Generator Replacement/Uprating Analysis and Licensing Project NSSS Licensing Report* (Submitted under HNP Letter Serial HNP-00-142, October 4, 2000, Accession Number ML003758761), Westinghouse drew from previous experience performing the V.C. Summer Steam Generator Replacement program, in which Westinghouse Model Δ75 replacement steam generators were installed, and the J. M. Farley Uprate program. The engineering and licensing reports produced for the Farley Uprate program were used as guides for preparing the HNP engineering and licensing documentation.

In Section 3.1.1 of this report it states that:

> "As part of the original design and analyses of the NSSS components for the HNP, NSSS design transients (i.e., temperature and pressure transients) were specified (Reference 1) for use in the analyses of the cyclic behavior of the NSSS components."

References
1. Systems Standard Design Criteria (SSDC) 1.3, Revision 2, April 15, 1974.

In the specific discussion of the pressurizer components and surge line, a chronology of the qualifications performed is included in the response to question Question No. 4.3-6.

Staff Evaluation
The applicant did not update its RCS piping specification. The staff considered that design analysis shall follow design specification.
Currently, design analysis does not follow the requirement of design specification. The staff requests applicant to provide a commitment to update piping specification.

Section 4.3 Metal Fatigue
Question No. 4.3-12

Request
In Sections 4.3.2.1 and 4.3.2.2 of the LRA, please clarify why the Class 1 piping thermal transients are applicable to Class 2 and 3 and B31.1 piping. Please also justify the text in the analysis sections of page 4.3-11, 4.3-12, and 4.3-13.

Response
Background
The piping specification associated with Class 2 and 3 and B31.1 piping states:

> "Stress analysis of piping shall be performed in accordance with ASME Section III using a stress range reduction factor (f) equal to 1.0."

The basis for the use of a stress range reduction factor (f) equal to 1.0 was provided to the NRC in the response to NRC Question 210.67 (Draft SER Open Item No. 354) in HNP Letter Serial LAP-83-429, dated September 19, 1983. The response states:

> "The use of f = 1.0 is justified by the fact that the total number of full temperature cycles over 40 years during which the various system are expected to be in service is less than 7,000 cycles. This applies to *any* system on Shearon Harris Project."

A copy of the piping specification was provided for NRC review in response to NRC Question 210.80 in HNP Letter Serial NLS-85-338, dated September 26, 1985. Supplement 3 to NUREG-1038, Safety Evaluation Report related to the Operation of Shearon Harris Nuclear Plant, Unit 1, dated May, 1986 states:

> "…the staff has concluded that the applicants' design specifications, design reports, and calculation files comply with ASME Code requirements and that adequate traceability exists in these documents relative to design commitments in the Final Safety Analysis Report (FSAR). Therefore, the staff considers Confirmatory Issue 4 resolved."

Class 2 and 3 piping
The affected Class 2 and 3 piping is effectively an extension of the adjacent Class 1 piping. Therefore, the cycle count depends closely on reactor operating cycles and can be estimated by a review of the limiting reactor coolant system design transients in FSAR Table 3.9.1-1. Of those Normal Conditions listed that are likely to produce full-range thermal cycles in a 40-year plant lifetime are the 200 Heatup and Cooldown cycles. Assuming that all Upset Conditions lead to full-range thermal cycles adds an additional 980 cycles for a total of 1180 occurrences. For the 60-year extended operating period, the number of full-range thermal cycles for these piping analyses would be proportionally increased to 1,770. This is only a fraction of the 7,000 full-range thermal cycles associated with a stress range reduction factor of 1.0. Therefore, the analysis for Class 2 and 3 piping has been projected to the period of extended operation using 10 CFR 54.21(c)(1) method (ii).
A License Renewal Application amendment is required to revise the Section 4.3.2.1 of the LRA.

B31.1 piping
The Main Feedwater System (and associated systems such as the condensate system) and Main Steam System (and associated systems such as the Steam Generator System) thermal cycles anticipated correspond to Heatup and Cooldown cycles. For the 60-year extended operating period, the number of full-range thermal cycles for these piping analyses would be proportionally increased to 300. Therefore, main feedwater and main steam components will not experience 7,000 cycles during the period of extended operation. The Auxiliary Feedwater System supplies feedwater to the secondary side of the steam generators at times when the normal feedwater system is not available, thereby maintaining the heat sink capabilities of the steam generator. The system provides an alternate to the Feedwater System during startup, hot standby and cooldown and also functions as an Engineered Safeguards System.

The Auxiliary Feedwater System is directly relied upon to prevent core damage during plant transients resulting from a loss of normal feedwater flow, steam line rupture, main feedwater line rupture, loss of coolant accident (LOCA) and/or loss of off-site power by providing feedwater to the unaffected steam generators to maintain their inherent heat sink capability. The total number of cycles expected in 40 years of operation are as follows: 200 Heatup and Cooldown cycles, 2,000 cycles of feedwater cycling at hot standby, 980 cycles associated with all Upset Conditions, 240 cycles of quarterly AFW pump tests in accordance with ASME Section XI and 40 cycles of tests per the plant Technical Specifications. This yields a total of 3,460 cycles. For the 60-year extended operating period, the number of full-range thermal cycles for these piping analyses would be proportionally increased to 5,190. Therefore, auxiliary feedwater components will not experience 7,000 cycles during the period of extended operation.

The emergency diesel generators in the Emergency Diesel Generator System undergo monthly surveillance tests in accordance with plant Technical Specifications. For the 60-year extended operating period, the number of full-range thermal cycles for these piping analyses would be proportionally increased to 720. Therefore, the emergency diesel generator diesel exhaust piping will experience significantly fewer than 7,000 equivalent full temperature cycles during the period of extended operation. The security diesel generator in the Security Power System undergoes a monthly surveillance test to satisfy fire protection program surveillance requirements. For the 60-year extended operating period, the number of full range thermal cycles for these piping analyses would be proportionally increased to 720. Therefore, the security diesel generator diesel exhaust piping will experience significantly fewer than 7,000 equivalent full temperature cycles during the period of extended operation.

The diesel-driven fire pump in the Fire Protection System undergoes a monthly test to satisfy fire protection program surveillance requirements. For the 60-year extended operating period, the number of full-range thermal cycles for these piping analyses would be proportionally increased to 720. Therefore, the diesel-driven fire pump piping will experience significantly fewer than 7,000 equivalent full temperature cycles during the period of extended operation.

Therefore, the analysis for B31.1 piping has been projected to the period of extended operation using 10 CFR 54.21(c)(1) method (ii). An amendment is required to revise the Section 4.3.2.2 of the LRA.

A License Renewal Application amendment is required.

Staff Evaluation

The applicant reviewed each ASME Class 2 and 3 piping system and B31.1 piping system and determined that the piping is subjected to less than 7000 cycles for 60 years operation period. The staff also determined that the plant will not change its operation 3 times per week, which is equaivalent to 7000 cycles for 60 years. On this basis, the staff finds that the Class 2 & 3 and B31.1 piping fatigue analyses are still valid. The staff does not agree that the Class 2 & 3 piping are the extension of class 1 piping and subject to same cycle counting.

Section 4.3 Metal Fatigue
Question No. 4.3-13

NRC Request:
In Section 4.3.5.2 (page 4.3-19, Analyses) of the LRA, it states that the total number of cycles will be extrapolated to 60 years and 100 years. Why were the cycles extrapolated to 100 years?

HNP Response:
The discussion of cycle extrapolation was added to show the conservative nature of the evaluation. The extraneous text related to 100 years will be removed. A License Renewal Application amendment is required.

Staff Evaluation
This question is for clarification purpose only. LRA is for 60 years only. Therefore, extrapolation to 100 years is not required.

Section 4.3 Metal Fatigue
Question No. 4.3-14

Request
In Table 4.3-2 (page 4.3-25) of the LRA, why do List Numbers 80 and 82 (Cold Leg Safety Injection and Hot Leg Safety Injection for recirculation only) have exactly the same fatigue usage factor?

Response:
The design fatigue evaluations of the Hot Leg safety injection nozzles were performed conservatively with an enveloping evaluation using the Cold Leg safety injection nozzles analysis. Therefore, the reported design usage values are the same.

Safety injection occurs in three types of nozzles for HNP: Safety Injection Cold Leg (SI CL), Safety Injection Hot Leg (SI HL), and Accumulator Injection to Cold Leg. There is one of each type on each of three loops. The summary of design fatigue usage indicates that the SI CL and SI HL nozzles all report design usage of 0.7, while the Accumulator injection nozzles report 0.45. Review of other documentation reveals that the SI HL nozzles were qualified by using the SI CL nozzle transients and generic basis, since the injection transients conservatively enveloped the additional RHR return transient specified for the HNP SI HL piping. Based on these observations, the controlling SI nozzle location for evaluation of environmental effects is actually the SI CL nozzle. Elements of the SI HL nozzle thermal effects are also taken into consideration during the Fen evaluation, to assure that any potential differences of the nozzle on the hot leg (e.g., higher loop temperature and loop transient differences) are covered in the evaluation of the SI CL nozzle.

Staff Evaluation
On the basis of the fatigue evaluation of the hot leg safety injection nozzles is conservatively enveloped by using fatigue evaluation Of cold leg safety injection nozzle, the fatigue value is the same. The staff finds this acceptable.

Question No. 4.3-15

Request
In Table 4.3-3 (page 4.3-26) of the LRA, please provide the following clarifying information:

- The charging nozzle CUF is 0.89.

Which nozzle is this when compared to the information provided in Table 4.3-2?

- The safety injection nozzle CUF is 0.93.

Which nozzle is this when compared to the information provided in Table 4.3-2?

HNP Response

1. The charging nozzle CUF of 0.89 is the result of an enveloping evaluation of both the normal and alternate charging nozzles.

2. The limiting safety injection nozzle evaluated was the 6 inch Cold Leg safety injection nozzle.

Staff Evaluation:
This question is for clarification purpose. The applicant enveloped two nozzles' result in the Table 4.3-2. The staff finds this clarification is acceptable.

Section 4.3 Metal Fatigue
Question No. 4.3-16

Request
Table 4.3-1 (pages 4.3-21 and 4.3-22) provides 60-year NSSS Transient Cycle Projections. Please provide the following information:

1. Explain why the cycles to-date and the 60-year projected cycles can be zero.

2. It appears that some transients may not be specifically applicable to Shearon Harris. Please explain why these cycles have been added to this table (Normal Transients 13 and 14 and Upset Transient 8). How many cycles are associated with the 5 OBEs (Upset Transient 13)?

3. For the Test Condition, please explain where pre-operational testing cycles were considered.

HNP Response
The general deletion of cycle projections as a qualification basis for fatigue-related TLAAs is addressed in the response to Question No. 4.3-2.

1. The cycle projections will be removed from the License Renewal Application. Cycle projections will not be used to justify acceptability of fatigue-related TLAAs by 10 CFR 54.21(c)(1)(i) - the analyses remain valid for the period of extended operation. Normal Transients 5, 11, and 12, "Step Load Increase of 10% of Full Power", "Unit Loading from 0% to 15% Power", and "Unit Unloading from 15% to 0% Power": Cycles to-date are zero, based on the analysis of a 5.26-year sample of Plant Instrumentation (PI) data. Normal Transients 11 and 12 exist to address low power feedwater operations. Feedwater operations during the 0% to 15% power range are assumed to transition from auxiliary feedwater to main feedwater. Additionally, main feedwater is assumed to start at 32°F during the power increase and cool to 32°F during the power decrease. At HNP, all feedwater operations at low power conditions that could potentially affect the primary systems and equipment are being tracked through HNP's cycle counting program. This tracking provides a much better understanding of the transients than simply monitoring the numbers of occurrences of the 0% to 15% transients. The HNP cycle counting program is used to track the following related events:

   - Feedwater Cycling At Hot Standby, 2000 cycles with an alarm limit of 1500.
   - Main Feedwater Nozzle Temperature - Plant Loading Between 0 & 15% Power With Feedwater < 100°F, 60 cycles with an alarm limit of 42.
   - Main Feedwater Nozzle Temperature - Plant Loading Between 0 & 15%, 180 cycles with an alarm limit of 126.
   - Auxiliary Feedwater Nozzle Temperature And Flow Cycle, 2000 cycles with an alarm limit of 1500.

   Progress Energy operates HNP as a base-load generator (i.e., HNP is not a "load following" plant). Normal Transient 5, while not precluded, the accumulation rate is considered very low in comparison to the allowed design cycles.

   Normal Transients 8, 9, and 15, "Steady State Fluctuations (Initial)", "Steady State Fluctuations (Random)", and "Boron Concentration Equalization", are not counted. Prior to plant operation and the establishment of plant cycle counting procedure, it was concluded that the design limits would never be

reached, based on the expected number of cycles. The temperature changes associated with Steady State Fluctuations (Initial)" and "Steady State Fluctuations (Random)" are small (≤ 3°F). Therefore, these transients are not contributors to CUF. "Boron Concentration Equalization" transients are associated with the operation of a "load following" plant. Progress Energy operates HNP as a base-load generator (i.e., HNP is not a "load following" plant). Normal Transient 15, while not precluded, the accumulation rate is considered very low in comparison to the allowed design cycles. The "Cycles To-Date" for these entries should be changed to "Not Counted". Normal Transient 16, "Turbine Roll Test": During the development of one of the basis documents, Operations personnel were queried specifically as to how many Turbine Roll Tests had been performed. As part of the inquiry, the NSSS vendor provided details concerning the transient as follows:

> *"The transient is assumed for turbine cycle checkout. The assumption is that RCP power is used to heat the primary system to normal operating pressure and temperature (no load conditions). The steam generated is used to perform a turbine roll test. The NSSS is assumed to cool down with a rate greater than 100°F /hr during the test. The total cooldown is approximately 110°F down from the no load temperature. The test is assumed to occur 20 times over the plant life."*

Operations stated that HNP performed one Turbine Roll Test in 1986 during initial construction, and none since that time. Upset Transient 1, "Loss of Load" has been is counted since the start of plant operations in accordance with the plant cycle counting procedure. The number of occurrences has been zero.

2. Normal Transients 13, 14, and Upset Transient 8 were included in the qualifications performed by WCAP-14778, Revision 1, "Carolina Power and Light Harris Nuclear Plant Steam Generator Replacement/Uprating Analysis and Licensing Project NSSS Engineering Report", September 2000. As noted in the license renewal basis document, "Normal Condition" transients 13 and 14 ("Loop Out of Service") are not applicable to the current HNP license. HNP is not currently licensed to operate with N-1 loops. The "Loop Out of Service" transients were included in the Westinghouse System Standard Design Criteria (SSDC 1.3, Rev. 2) so that the components are designed in case the plant is licensed to operate with N-1 loops. It was recommended by Westinghouse that the "Loop Out of Service" transients continue to be considered for the SGR/Uprating Project. Therefore, the transients were carried forward to the License Renewal fatigue evaluation. This also applies to "Upset" Transient 8 ("Inadvertent Startup of an Inactive Loop").

3. 10 cycles for each global OBE cycle as specified in the FSAR.

4. As defined in the HNP FSAR: The "Test Condition" transients include "Leak (Leakage) Tests" and "Hydrostatic Tests". The leakage tests are applicable during life of plant. Secondary side hydrostatic tests were to have been performed prior to plant startup or subsequently following shutdown for major repairs, or both. "Test Condition" transients 1, 2 and 5 are defined in FSAR 3.9.1.1.5 and "Test Condition" transients 3 and 4 are defined in FSAR 3.9.1.1.1. FSAR 3.9.1.1.5 states that primary side hydrostatic tests include both shop and field hydrostatic tests. These tests can occur as a result of component or system testing. FSAR 3.9.1.1.5 also states that four additional hydrostatic tests, in accordance with ASME Section XI inservice inspection (ISI) requirements, are expected over the lifetime of the plant. Since four additional tests in accordance with ASME Section XI ISI requirements were expected to be performed, and since one of these tests was performed and recorded, then no more than six shop tests were possible. Therefore, the total number of primary side hydrostatic can conservatively be no more than seven.

A License Renewal Application amendment is required.

Staff Evaluation

Evaluation of 1st Bullet: 60 years projected cycle

The applicant states that "The cycle projections will be removed from the License Renewal Application. Cycle projections will not be used to justify acceptability of fatigue-related TLAAs by 10 CFR 54.21(c)(1)(i) - the analyses remain valid for the period of extended operation." The staff reviewed the applicant's LRA Amendment 2 (ML072540804), dated 8/31/2007, and confirmed that cycle projections have been removed. On the basis of that cycle projections will not be used to justify acceptability of TLAA by 10CFR54.21(c)(1)(i) and cycle projections have been removed from LRA, the staff finds this acceptable.

Evaluation of Cycles to-date:

The staff reviewed the applicant's response and confirmed that LRA Amendment 2, dated 8/31/2007, has revised the cycles to-date column in Table 4.3-1 and provided detail explanation to address each transient as indicated in the Note of Table 4.3-1 for each transient which has zero cycle to-date. On this basis, the staff finds this issue closed.

Evaluation of 2nd Bullet:

The staff reviewed the applicant's design basis document, WCAP-14778, Revision 1, "Carolina Power and Light Harris Nuclear Plant Steam Generator Replacement/Uprating Analysis and Licensing Project NSSS Engineering Report", September 2000 to confirm that those transients related to N-1 loops operation are considered in the fatigue evaluation. On the basis of that HNP is not currently licensed to operate with N-1 loops and these transients will not occur, the staff finds that design analysis is conservative.

Evaluation of 3rd Bullet:

On the basis of FSAR statement, the staff finds this acceptable.

Evaluation of 4th Bullet:

The staff reviewed the response and confirmed that LRA Amendment 2 revised the number of cycles for the Primary Hydro test to address hydro test performed by shop. On this basis, the staff concludes this acceptable. The number of cycles for secondary side hydro test is not revised**.**
The staff is asking to provide additional justification to address this item (Does secondary side hydrotest include
5 shop tests also?)

Section 4.3 Metal Fatigue
Question No. 4.3-17

Request
Please explain how stresses are input to apply the stress transfer function of WESTEMS™, from the 6 stress components or the stress intensity. Please provide input and results of any benchmarking problems for pressure, temperature, or moment loadings.

HNP Response
See Page 67 to page 93 of Enclosure 3 of HNP LRA Amendment 2 (ML072540804), dated 8/31/2007.

Staff Evaluation
The staff reviewed the applicant's clarification which explains the method used for the stress transfer function of WESTERMS. On the basis of its review, the staff confirmed that the applicant superimposed stress at the component stress levels for each time step and for each applied loading type. The method is according to ASME Section III, Division 1, NB-3200 criteria.

The applicant also states that "The verification of WESTEMS™ thermal and mechanical stress calculations have been performed in the programs verification and validation documentation. However, each application verification of the finite element model and of the final thermal transfer function databases should be performed in order to show applicability to the problem being modeled. To do this for mechanical loads, Westinghouse verifies the finite element model results by comparing them to the expected theoretical values. For the time varying thermal results Westinghouse performs thermal stress analyses using both the finite element program and WESTEMS™." On the basis of that, the staff finds applicant's stress results are acceptable.

The staff also reviewed applicant's benchmark verification result. The benchmark results were plotted in Figures B-1 thru B-11 and additional results of sample 1 and sample 2 which all indicated that the stress results generated from WESTERM and the stress results generated from traditional finite element ANSYS analysis have negligible differences. On this basis, the staff concludes that stress evaluation by WESTERM is acceptable.

Section 4.3 Metal Fatigue
Question No. 4.3-18

NRC Request:
There are discrepancies in the Design CUF values between LRA and the basis document (WCAP-15398 Supplement 1, December 2001). For example, the CUF of main feedwater nozzle is 0.98 as shown in Table 5.7.1-2 of the WCAP-15398 (Supplement 1, which is different from the value (0.93) described in the LRA Table 4.3-2 (Design Fatigue Usage Factors). Please explain.

HNP Response:
The value of 0.93 in LRA Table 4.3-2 (List Number 31) is incorrect. It was taken from the original version of WCAP-15398 (September 2000). The correct value of 0.98 is from Supplement 1 of WCAP-15398. LRA Table 4.3-2 will be updated to incorporate the correct value.

A License Renewal Application amendment is required.

Staff Evaluation
The staff reviewed and confirmed that LRA Amendment 2 revised fatigue usage value listed in LRA Table 4.3-2 to make that CUF value is consistent with design basis document. On this basis, the staff finds this acceptable.

Section 4.6
Question No. 4.6.1

NRC Request
On page 4.6-2 of Section 4.6.1.1 of the LRA, it states that ILRT will be conservatively assumed to be performed every 5 years and this yields 12 cycles for 60 years. However, ILRT will be performed once every 10 years only after adopting 10 CFR 50, appendix J, Option B. When did HNP adopt Option B? If necessary, provide a correction to the LRA based on your response.

HNP Response:
HNP adopted Option B in 1999. A letter from the NRC from Richard J. Laufer to James Scarola of Carolina Power and Light Company, dated September 17, 1999, Subject: Shearon Harris Nuclear Power Plant, Unit 1 – Issuance of Amendment RE: Containment Integrated Leak Rate Testing (TAC No. MA5944), issued Amendment 91 to revise the Technical Specifications to incorporate performance-based 10CFR 50 Appendix J, Option B, for Type A containment integrated leakage rate testing. An ILRT has not been performed since issuance of Amendment 91. A preoperational Type A ILRT was performed February 25, 1986 and periodic Type A ILRTs were performed October 25, 1989, September 21, 1992 and May 23, 1997. The next ILRT (Option B Type A) is required no later than May 23, 2012 based on a onetime extension from once in 10 years to once in 15 years granted by the NRC in Amendment 122. This amendment was issued March 30, 2006 in a letter from the NRC from Chandu P. Patel to Cornelius J. Gannon of Carolina Power and Light Company, Subject: Shearon Harris Nuclear Power Plant, Unit 1 – Issuance of Amendment Regarding Containment Integrated Leak Rate Test (TAC No. MC6722).

The number of ILRTs performed to date is four counting the pre-operational test. The number of remaining ILRTs projected to the end of extended HNP plant life, from 2012 to 2046, on a 10-year interval is only an additional four, for a total of eight ILRTs. Therefore, for the remaining period of operation, including the license renewal period, a grand total of eight ILRTs is projected. The total of 12 ILRTs discussed in Section 4.6.1.1 of the LRA conservatively bounds the actual projected number of eight ILRTs. No change to the LRA is needed.

Staff Evaluation
The staff reviewed the applicant's response. On this basis of that the applicant's total of 12 ILRTs discussed in Section 4.6.1.1 of the LRA conservatively bounds the actual projected number of eight ILRTs, the staff finds this closed.

Section 4.7.4 (HELB Location Postulation Based on Fatigue CUF)
Question No. 4.7.4-1

Request

Question 4.7.4-1 (HELB location postulation based on fatigue CUF)
LRA section 4.7.4 indicates that current usage factors used for the postulation of break locations in Class 1 piping may be used for the 60 year operating term. However, Section 4.3.1.7 of the LRA indicates that the pressurizer surge line was not bounded by the original 40 year design transients and was subsequently reanalyzed for 60-year transients. Clarify whether there are any Class 1 piping locations where the cumulative usage factor may exceed 0.1 during the period of extended operation.

HNP Response
The discussion in Section 4.3.1.7 was provided to indicate that a more detailed evaluation was required. The detailed evaluation included the effects of surge line transients considering the effects of thermal stratification and plant-specific cyclic data. The effects of reactor water environment on fatigue are described in LRA Section 4.3.3. A review of the analysis prepared for license renewal provided the values of cumulative usage factors before the application of the fatigue life correction factor (Fen). The unadjusted cumulative usage factor (U) at the hot leg nozzle safe end to pipe weld is 0.1138. The unadjusted cumulative usage factor (U) at the pressurizer nozzle safe end to pipe weld is 0.0288. However, these are based on 133 heatup/cooldown cycles projected for 60 years. For the remaining non-heatup/cooldown transients, the 40-year design number of cycles was included in the fatigue pairs.

Extrapolating the unadjusted CUF to the design limit of 200 heatup/cooldown cycles can be accomplished as follows: U200 = U133 * 200/133. This yields CUFs of 0.1711 at the hot leg nozzle safe end to pipe weld and 0.0433 at the pressurizer nozzle safe end to pipe weld. These values can then be compared to the current licensing basis (CLB) values 0.85 and 0.2, respectively. The cumulative usage factors from the refined analysis prepared for license renewal, when adjusted for the full 40-year design cycles, are bounded by the existing CLB analysis. Therefore, the break locations postulated in the CLB remain applicable.

Staff Evaluation
The staff reviewed the applicant's response and basis document for the refined CUFs calculation. On the basis of that the CUFs from the refined analysis prepared for license renewal, when adjusted for the full 40-year design cycles, are bounded by the existing CLB analysis, the break locations postulated in the CLB remain applicable. Therefore, the staff finds this acceptable..