Progress Energy

Crystal River Nuclear Plant
Docket No. 50-302
Operating License No. DPR-72

Ref: 10 CFR 54

October 13, 2009
3F1009-07

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

Subject: Crystal River Unit 3 – Response to Request for Additional Information for the Review of the Crystal River Unit 3 Nuclear Generating Plant License Renewal Application (TAC NO. ME0274) and Amendment #5

References:
(1) CR-3 to NRC letter, 3F1208-01, dated December 16, 2008, "Crystal River Unit 3 – Application for Renewal of Operating License"

(2) NRC to CR-3 letter, dated September 11, 2009, "Request for Additional Information for the Review of the Crystal River Unit 3 Nuclear Generating Plant License Renewal Application (TAC NO. ME0274)"

Dear Sir:

On December 16, 2008, Florida Power Corporation (FPC), doing business as Progress Energy Florida, Inc. (PEF), requested renewal of the operating license for Crystal River Unit 3 (CR-3) to extend the term of its operating license an additional 20 years beyond the current expiration date (Reference 1). Subsequently, the Nuclear Regulatory Commission (NRC), by letter dated September 11, 2009, provided a request for additional information (RAI) concerning the CR-3 License Renewal Application (Reference 2). Enclosure 1 to this letter provides the response to Reference 2. Enclosure 2 provides Amendment #5 to the License Renewal Application. A listing of CR-3 License Renewal Commitments, updated to reflect changes made during the NRC review of the License Renewal Application, is included in Enclosure 3.

In consideration of the recent discovery of a gap in the concrete of the outer radius of the containment structure (NRC Event Notification 45416 dated October 7, 2009 and NRC Special Inspection Team Press Release No. II-09-055 dated October 9, 2009), FPC will evaluate the need to revise any of the technical responses to this NRC request for additional information. This evaluation will be complete following the root cause determination that is currently in progress and subsequent assessment of any impact on the technical and aging management programs discussed in this response.

If you have any questions regarding this submittal, please contact Mr. Mike Heath, Supervisor, License Renewal, at (910) 457-3487, e-mail at mike.heath@pgnmail.com.

Sincerely,

Jon A. Franke
Vice President
Crystal River Unit 3

JAF/dwh

Enclosures:
1. Response to Request for Additional Information (Reference 2)
2. Amendment #5 - Changes to the License Renewal Application
3. CR-3 License Renewal Commitments, Revision 1

xc: NRC CR-3 Project Manager
NRC License Renewal Project Manager
NRC Regional Administrator, Region II
Senior Resident Inspector

A035
A001
NRR

Progress Energy Florida, Inc.
Crystal River Nuclear Plant
15760 W. Power Line Street
Crystal River, FL 34428

STATE OF FLORIDA

COUNTY OF CITRUS

Jon A. Franke states that he is the Vice President, Crystal River Nuclear Plant for Florida Power Corporation, doing business as Progress Energy Florida, Inc.; that he is authorized on the part of said company to sign and file with the Nuclear Regulatory Commission the information attached hereto; and that all such statements made and matters set forth therein are true and correct to the best of his knowledge, information, and belief.

Jon A. Franke
Vice President
Crystal River Nuclear Plant

The foregoing document was acknowledged before me this 13 day of October, 2009, by Jon A. Franke.

Carolyn E Portmann

Signature of Notary Public
State of Florida

CAROLYN E. PORTMANN
Notary Public - State of Florida
My Commission Expires Mar 1, 2010
Commission # DD 524380
Bonded By National Notary Assn.

(Print, type, or stamp Commissioned Name of Notary Public)

Personally Known ✓ -OR- Produced Identification ______

PROGRESS ENERGY FLORIDA, INC.

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50 - 302 / LICENSE NUMBER DPR - 72

ENCLOSURE 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION

Request for Additional Information (RAI) 3.3.2-38-1

Background:

Accurate identification of material and environment combinations, as described in NUREG 1801, "Generic Aging Lessons Learned (GALL) Report," is necessary to support aging management reviews.

Issue:

License renewal application (LRA) Table 3.3.2-28, "Aging Management Evaluation for Instrument Air Dryers" describes the instrument air dryers as stainless steel with an internal environment of dried air. During the material/environment verification audit walkdown, the U.S. Nuclear Regulatory (NRC) staff noticed that the instrument air dryers appear to be carbon steel rather than stainless steel as described in LRA Table 3.3.2-28. Also, the internal environment of the dryers, in accordance with the vendor manual, contains alumina desiccant. Further review of the applicable drawings and vendor information did not clarify the type of information for this component.

Request:

Provide the documentation to show that the instrument air dryers material is stainless steel and confirm the internal environment or correct the material and environment descriptions in LRA Table 3.3.2-28.

Response

LRA Table 3.3.2-38, Auxiliary Systems – Summary of Aging Management Evaluation - Instrument Air System, identifies that the Instrument Air Dryers are constructed of carbon steel, stainless steel, and copper alloys. The instrument air dryers have an internal environment of dried air and contain dessicant which is inspected and replaced periodically. Instrument air system components that are located upstream of the air dryer skids do not contain dried air and are considered to have an air indoor – uncontrolled environment. The main portions of the instrument air dryers are constructed of carbon steel based on discussions with the CR-3 system engineer and as verified in the plant. Other minor components located on the instrument air dryer skids (e.g. tubing, fittings) are constructed of stainless steel and copper alloys.

RAI B.2.1-1

Background:

The Crystal River Unit 3 Nuclear Generating Plant (CR-3) LRA Section B.2.1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" states that the aging management program (AMP) is "an existing program consistent with NUREG-1801, Section XI.M1."

GALL Report, Section XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" recommends the use of American Society of Mechanical Engineers (ASME) Section XI Table IWB-2500-1 to determine the examination of Category B-F and B-J welds. CR-3 is currently using examination Category R-A in accordance with risk-informed methodology approved by the NRC under 10 CFR Part 50, for use during the current ten-year interval for examination of Table IWB-2500-1, Category B-F and B-J welds.

Issue:

The approval of the risk-informed methodology cannot be assumed for the subsequent intervals.

Request:

Clarify how the inspection of Categories B-F and B-J will be implemented during the extended period of operations.

Response

CR-3 will comply with 10 CFR 50.55a for the extended period of operation as required by the plant's operating license, including requirements for implementing ASME Section XI, Subsection IWB, IWC, and IWD inspections.

RAI B.2.2-1

Background:

The Monitoring and Trending section of the Water Chemistry AMP in the GALL Report, Section XI.M2, includes periodic monitoring and control of known detrimental contaminants in accordance with the Electric Power Research Institute (EPRI) water chemistry guidelines for pressurized water reactors (PWR). EPRI report 1014986, "Pressurized Water Reactor Primary Water Chemistry Guidelines" (2007) provides guidance to monitor silica in the reactor coolant system during startup daily as indicated in Table 3-8.

Issue:

The CR-3 LRA, Appendix B, Section B.2.2, indicates that the applicant's Water Chemistry Program is consistent with the GALL Report Section XI.M2 and does not take any exceptions. It was indicated in the applicant's basis document L08-0601, Water Chemistry AMP, in Table 6.2-1 on Page 12, that periodic monitoring and control of chemistry parameters are delineated in the EPRI Water Chemistry Guidelines. In addition, the applicant's document entitled, "Crystal River Unit 3 Optimized Primary Chemistry Program" indicates that it has adopted daily measurement of silica consistent with the EPRI Water Chemistry Guidelines. The applicant's CH-400 report, "Nuclear Chemistry Master Scheduling Program" provides the schedules for the chemistry monitoring. The CH-400 does not provide guidelines for measuring silica in the reactor coolant system during reactor startup, which is included in the EPRI guidelines and the CR-3 Optimized Primary Chemistry Program.

Request:

Provide additional information on the total silica monitoring program during reactor system startup that clarifies the discrepancy between the CR-3 Optimized Primary Chemistry Program and CH-400 monitoring schedule.

Response

The sampling procedure is consistent with the EPRI guidelines, and the discrepancy between it and the Master Scheduling procedure is being corrected.

RAI B.2.3-1

Background:

In LRA Appendix B, Section B.2.3, the applicant stated that the Reactor Head Closure Studs Program has an enhancement to select an alternate lubricant that is compatible with the fastener material and the contained fluid. The applicant also stated that except for the enhancement the program is consistent with the GALL Report.

NRC Regulatory Guide (RG) 1.65 is one of the technical references for the GALL Report, "Reactor Head Closure Studs Program" (AMP XI.M3) and states the regulatory position that lubricants for the stud bolting are permissible provided they are stable at operating temperatures and are compatible with the bolting and vessel materials and surrounding environment.

Issue:

The staff noted that a molybdenum disulfide based lubricant is used for the reactor head closure studs. It should be clarified whether the lubricant, which has been used, caused detrimental effects on the bolting and vessel materials. In addition, the staff found a need to clarify how the selection of a new lubricant will consider the stability of the lubricant at operating temperatures as recommended in RG 1.65.

Request:

1. Confirm whether operating experience indicates that the currently used lubricant has caused detrimental effects on the bolting materials.

2. Clarify how the selection of a new lubricant will consider the stability of the lubricant at the operating temperatures as recommended in RG 1.65.

Response

1. *The 90-day inspection reports for the last 5 outages were reviewed. All examination results were acceptable.*

2. *The lubricant selected is Loctite® High Purity N5000™ Anti-Seize. Loctite® High Purity N5000™ Anti-Seize is a nickel-based, anti-seize lubricant, which can be used in applications with a dry surface temperature as high as 2400° F.*

RAI B.2.4-1

Define the Section 8.3 "Deviation" process of Procedure EGR-NGGC-0207 for the Boric Acid Corrosion Program including responsibilities, documentation requirements, as well as the review and authorization process.

Response

EGR-NGGC-0207, Section 8 (Acceptance Criteria) states:

8.1 Borated system leakage is not acceptable. These leaks must be repaired to ensure continued pressure boundary component integrity, except as specified in 8.3.

8.2 Boric acid residue on equipment susceptible to boric acid corrosion or otherwise adversely affected by boric acid residue, such as electrical equipment, shall be cleaned, except as specified in 8.3. The remaining residue shall have no visible thickness such that the condition of the underlying metal can be readily determined.

8.3 Deviations to the acceptance criteria shall be documented and reviewed for acceptability for continued service.

Consistent with the Acceptance Criteria in EGR-NGGC-0207, a deviation in the context of Step 8.3 is an instance wherein a decision is made either to defer the repair of an active leak, or not to clean boric acid residue from susceptible equipment, and is generally based on plant conditions or configuration. This is an infrequent occurrence that is procedurally governed, has the oversight and involvement of the BACC Program Manager, and, if there is the potential for component degradation, is documented, tracked, and resolved using a Nuclear Condition Report (NCR), within the controls of the Corrective Action Program.

RAI B.2.4-2

Guidance for the aging management of other nickel-alloy nozzles and penetrations is provided in the aging management review (AMR) line items of Chapter IV, as appropriate.

Commitment 2 of the License Renewal Commitments of Enclosure 2 of the CR-3 application states:

> In accordance with the guidance of NUREG-1801, Rev. 1, regarding aging management of nickel alloy and nickel-clad components susceptible to primary water stress corrosion cracking, CR-3 will comply with applicable NRC Orders and will implement applicable: (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines.

During the license renewal audit process at CR-3, the applicant's response to NRC issues related to the aging management of nickel alloy and nickel-clad components susceptible to primary water stress corrosion cracking was that Commitment 2 would answer these issues when a Ni-based Alloy Aging Management Program would be submitted to the NRC, two years prior to the beginning of the license renewal period. However, Commitment 2 does not commit to the submittal of this report within that timeline. Confirm and/or clarify Commitment 2 in the Program Implementation Schedule.

Response

CR-3 is currently pursuing actions associated with the aging management of nickel alloy and nickel-clad components. However, for the purposes of license renewal, CR-3 will be consistent with the guidance of NUREG-1801, Revision 1, as described in Commitment 2.

RAI B.2.5-1

Background:

As provided in GALL AMP XI.M11A, the augmented inspection requirements established in First Revised Order EA-03-009 include visual VT-2 and nondestructive examinations. The final rule for Title 10 of the *Code of Federal Regulations* (CFR) Part 50.55a supersedes the Revised Order and requires all licensees to augment their inservice inspection program with ASME Code Case N-729-1. The examination requirements for reactor vessel upper heads are visual examination, volumetric, and/or surface examination. Personnel performing the visual examination shall be qualified as a VT-2 visual examiner and shall have completed at least four hours of additional training in detection of borated water leakage.

Issue:

The applicant's Inservice Inspection (ISI) Components and Structures Examination Program, Revision 8 states that Code Case N-729-1 will be implemented until Refuel Outage 18 in 2013 in accordance with 10 CFR 50.55a. The applicant also states that the reactor vessel upper head shall receive a visual inspection every other outage starting with the first outage after January 1, 2009, and a volumetric inspection not to exceed every ten calendar years following the initial examination. However, specific schedules for the visual and volumetric inspections and implementation of the additional training for visual examination are not provided.

Request:

Clarify the specific schedules for the visual and volumetric inspections and how the additional training for visual examination will be implemented.

Response

The Inspection (ISI) Components and Structures Examination Program is currently in revision. Visual inspections in accordance with Code Case N-729-1 are scheduled for October 8, 2009. Volumetric examinations are scheduled for Refuel Outage 18 (Fall 2013). The requirements of Code Case N-729-1 subject to the conditions specified in paragraphs (g)(6)(ii)(D)(2) through (6) of 10 CFR 50.55a have been incorporated into the current ISI Program Plan.

RAI B.2.6-1

Background:

The scope of the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Aging Management Program in the GALL Report, Section XI.M13 includes consideration of synergistic loss of fracture toughness due to both neutron embrittlement and thermal aging embrittlement. In addition, under the parameters monitored/inspected, the CASS materials identified include those with neutron fluences of greater than 10^{17} n/cm^2 (E>1 MeV) or those that are susceptible to thermal embrittlement.

Issue:

The CR-3 LRA, Appendix B, Section B.2.6, indicates that the applicant's Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program is consistent with the GALL Report Section XI.M13 and does not take any exceptions. It was indicated in the applicant's basis document L08-0607, Thermal Aging and Neutron Irradiation Embrittlement of CASS, in Table 6.2.1 on Page 9, that unless the CASS component is subjected to a fluence level of 10^{21} n/cm^2 (E>1 MeV) or higher, the synergistic effect of thermal aging and neutron irradiation embrittlement need not be evaluated. EPRI report 1015395, "Plant Support Engineering: Utility Cast Austenitic Stainless Steel Component Aging Management Inspection Needs" is referenced in regards to this conclusion, but does not provide the basis data that supports this assertion.

Request:

Provide additional information that justifies limiting the synergistic loss of fracture toughness consideration to fluence levels greater than 10^{21} n/cm^2 (E>1 MeV) in lieu of the GALL Report recommended 10^{17} n/cm^2 (E>1 MeV) limit. Describe whether this proposal limit is consistent with other industry work (e.g. EPRI MRP-227, "PWR Reactor Internals Inspection & Evaluation Guidelines").

Response

The basis document has been updated to include the latest information available from the Materials Reliability Program (MRP). The purpose of MRP-175, "PWR Internals Material Aging Degradation Mechanism Screening and Threshold Values," was to develop and provide the technical bases for screening criteria for age-related degradation evaluation of Pressurized Water Reactor internals component items. This report was prepared under the direction and sponsorship of the EPRI MRP Reactor Internals Issue Task Group (RI-ITG). This report is considered a key element in an overall strategy for managing the effects of aging in PWR internals using knowledge of internals design, materials and material properties, and applying screening methodologies for known aging degradation mechanisms. A non-proprietary version of this report was provided to the NRC on July 6, 2006 (ADAMS Accession Number ML061880262).

The screening criteria in MRP-175 are referenced by MRP-189, "Screening, Categorization, and Ranking of B&W-Designed PWR Internals Component Items," Revision 1, March 2009. For cast austenitic stainless steel (CASS), a threshold of >$6.7X10^{20}$ n/cm^2 (E>1 MeV) is indicated for susceptibility to irradiation embrittlement. When evaluating CASS materials the threshold is lowered to ≥$3.3X10^{20}$ n/cm^2 (E>1 MeV) to account for potential synergistic effects. MRP-189, Revision 1 was provided to the NRC under ADAMS Accession Numbers ML091671777 (June 10, 2009) and ML092230734 (August 4, 2009).

These reports were incorporated by reference into MRP-227, Pressurized Water Reactor Internals Inspection and Evaluation Guidelines. This report was submitted to the NRC on

January 12, 2009 (ADAMS Accession Number ML090160204). In this submittal, EPRI requested that the NRC issue a safety evaluation report for MRP-227.

The aging management strategies for the subject components are derived from MRP-227. When a Safety Evaluation Report is issued for MRP-227, any required actions that affect the aging management strategy for these components will be incorporated into the program documents.

The LRA will be revised to state that the augmented inspections for the CASS reactor vessel internals components are in conformance with MRP-227, "Pressurized Water Reactor Internals Inspection and Evaluation Guidelines." When a Safety Evaluation Report is issued for MRP-227, any required actions that affect the aging management strategy for these components will be incorporated into the program documents. Refer to Enclosure 2.

As indicated in Enclosure 3, License Renewal Commitment #4 should be revised to state:

> *The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new program to be implemented. When a Safety Evaluation Report is issued for MRP-227, any required actions that affect the aging management strategy for these components will be incorporated into the program documents.*

RAI B.2.6-2

Background:

The detection of aging effects of the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Aging Management Program in the GALL Report, Section XI.M13 indicates that the 10-year ISI program include a supplemental inspection for those components that have a fluence of greater than 10^{17} n/cm^2 (E>1 MeV) or are susceptible to thermal embrittlement, unless a component-specific evaluation determines it unnecessary. In addition, the guidance indicates that the inspection technique used should be capable of detecting the critical flaw size with adequate margin, which will be based on service loading conditions and service-degraded material properties.

Issue:

The CR-3 LRA, Appendix B, Section B.2.6, indicates that the applicant's Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel Program is consistent with the GALL Report, Section XI.M13 and does not take any exceptions. It was indicated in the applicant's basis document L08-0607, Thermal Aging and Neutron Irradiation Embrittlement of CASS, in Table 6.2.1 on Page 13, that unless a component specific evaluation is conducted, the susceptible components will be inspected under an augmented inspection program. The inspection technique and acceptance criterion is to be determined by the CR- 3 ISI Program Manager, and that the GALL Report recommendations must be "considered." In the LRA, Section B.2.6, the applicant indicated that the Thermal Aging and Neutron Irradiation Embrittlement of CASS program will be implemented and required inspections completed during the last 10-year ISI interval prior to the period of extended operation. The applicants basis document L08-0607 indicated that the "augmented inspection," which is part of the program will be identified as an augmented inspection in their basis document AI-701, "Administration of the

ASME Section XI Inservice Inspection and Inservice Testing Programs." However this document did not provide further basis data on the techniques that will be used during the last 10-year ISI interval and through the extended operation period.

Request:

Provide additional information on the augmented inspection program of the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel program B.2.6 that indicates how it is consistent with the GALL Report guidance.

Response

The basis document has been updated to include the latest information available from the MRP-227, "Pressurized Water Reactor Internals Inspection and Evaluation Guidelines." The implementing document has been changed to ISINDEPM-1, "ISI Components and Structures Examination Program." Per MRP-227, the inspections of the "Primary Components" are as follows:

The CSS vent valve discs, CSS vent valve top retaining ring, CSS vent valve bottom retaining ring, and CSS vent valve disc shaft or hinge pin will require a Visual (VT-3) examination. The initial examination is to be performed during the next 10-year ISI. Subsequent examinations are to occur on the 10-year ISI interval. The specific relevant condition is evidence of surface irregularities, such as damaged or fractured disc material. There is an "Expansion Link" to the Control Rod Guide Tube (CRGT) spacer castings. The expansion criteria is confirmed evidence of relevant conditions in two or more CSS vent valve discs shall require that the VT-3 examination be expanded to include 100% of the accessible surfaces at the 4 screw locations (at every 90°) of the CRGT spacer castings by the completion of the next refueling outage.

In addition, a verification of the operation of each vent valve shall also be performed through manual actuation of the valve. This is to verify that the valves are not stuck in the open position and that no abnormal degradation has occurred. Examine the valves for evidence of scratches, pitting, embedded particles, variation in coloration of the seating surfaces, cracking of lock welds and locking cups, jack screws for proper position, and wear. The examination frequency of every refueling outage is defined in the ASME Section XI/ASME OM Code Interval 4 Inservice Testing Program Pump and Valve Manual. The inspections are performed in accordance with SP-202, "Reactor Vessel Internal Vent Valve Exercise."

The Incore Monitoring Instrument Guide Tube Spiders are to receive an initial visual (VT-3) examination no later than two refueling outages from the beginning of the license renewal period. Subsequent examinations occur on a ten-year interval. The examination coverage is 100% of accessible top surfaces of 52 spider castings and welds to the adjacent lower grid rib section.

The CRGT Spacer Castings are "Expansion Components." As such, if an examination is required, it will be a Visual (VT-3) Examination of 100% of accessible surfaces at the 4 screw locations (at every 90°).

MRP-227 was submitted to the NRC on January 12, 2009 (ADAMS Accession Number ML090160204). In this submittal, EPRI requested that the NRC issue a safety evaluation report for MRP-227.

When a Safety Evaluation Report is issued for MRP-227, any required actions that affect the aging management strategy for these components will be incorporated into the program documents.

NUREG-1801, XI.M13, under the discussion of "Detection of Aging Effects" states in part:

> *For reactor vessel internal CASS components that have a neutron fluence of greater than 10^{17} n/cm^2 (E>1 MeV) or are determined to be susceptible to thermal embrittlement, the 10-year ISI program during the renewal period includes a supplemental inspection covering portions of the susceptible components determined to be limiting from the standpoint of thermal aging susceptibility...*

The specified supplemental inspections are based on CR-3's participation in the industry programs for investigating and managing aging effects on reactor internals and are the implementation of the results of those industry programs and are therefore consistent with the requirements of NUREG-1801.

RAI B.2.7-1

Background:

In LRA Section B.2.7.1-1, the applicant states that the CR-3 Flow-Accelerated Corrosion (FAC) Program described in EGR-NGGC-0202, "Flow Accelerated Corrosion Monitoring Program," Revision 10, is based on EPRI guidance document NSAC-202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program," Revision 3, dated May 2006.

Issue:

The GALL Report recommends the use of Revision 2 of the NSAC-202L.

Request:

Please provide a discussion of the differences between Revisions 2 and 3 of the EPRI guidance document NSAC-202L and provide a discussion as to why this is not considered an exception to the GALL Report.

Response

Revision 3 of NSAC-202L contains recommendations updated with the worldwide experience of members of the CHECWORKS™ Users Group (CHUG), plus recent developments in detection, modeling, and mitigation technology. These recommendations are intended to refine and enhance those of the earlier versions, without contradiction, so as to ensure the continuity of existing plant FAC programs. The guidance contained in Revision 3 of NSAC-202L supersedes that contained in EPRI Report NP-3944 and all prior versions of NSAC-202L. Revision 2 of NSAC-202L states that the document will be periodically updated to reflect the advances made in FAC control.

Revision 3 to NSAC-202L provides for better programmatic guidance with the following improvements which include:

- *adding the most significant FAC experience events through December 2005,*
- *adding a number of definitions,*
- *expanding discussion of the use of safety factors,*
- *enhancing the guidance on determining intervals for re-inspections,*
- *enhancing the guidance on susceptible-not-modeled lines,*
- *enhancing the guidance for inspection of vessels, tanks, valves, orifices and equipment nozzles, and*
- *adding sections for use of radiographic testing to inspect large-bore piping, inspection of turbine cross-around piping, and inspection of valves.*

In summary, EPRI Report NSAC-202L-R3 provides enhanced guidance with lessons learned since Revision 2 of this document was published in April 1999, updates the worldwide FAC operating experience, and provides recent developments in detection, modeling, and mitigation technology without contradiction of the previous revision. Both Revision 3 and Revision 2 of NSAC-202L present a set of recommendations for nuclear power plants to implement an effective program in detecting and mitigating FAC. Based on the above information, the use of EPRI NSAC-202L, Revision 3, meets the intent of NUREG-1801, Section XI.M17, and so is not considered an exception to the GALL Report.

RAI B.2.7-2

Background:

In LRA Section B.2.7, the applicant states that the FAC Program monitors the effect of FAC on the intended function of piping and components by measuring wall thickness. It was further stated that selection and prioritization of components to be inspected consider NSAC-202L, using the following criteria: CHECWORKS model predictions, trending, consequences of failure, engineering judgment, and plant and industry operating experience events.

Issue:

The LRA did not contain information regarding the accuracy of the FAC Program in predicting FAC degradation in components.

Request:

Please provide a sample list of components for which wall thinning is predicted and measured by ultrasonic testing or other methods in order to assess the accuracy of the FAC predictions from CHECWORKS. This list should also include the initial wall thickness (nominal), current (measured) wall thickness, and a comparison of the measured wall thickness to the thickness predicted by the CHECWORKS FAC model.

Response

A sample list of Condensate (CD) System components has been provided for which wall thinning is predicted and measured by ultrasonic testing (UT). This list includes the initial wall thickness (nominal), current (measured) wall thickness, and the thickness predicted by the CHECWORKS FAC model.

Attached is the Wear Rate Analysis: Combined Summary Report for Condensate System Train A and Train B piping for this sample list of components. The report identifies the requested thicknesses for various Condensate System piping segments. As an example, for Component Name 111-010P (P = piping) the initial wall thickness (nominal) is 0.375 in., the current (measured) wall thickness is 0.330 in., and the thickness predicted by the CHECWORKS FAC model is 0.311 in. The subject components are shown on scoping drawing 302-101-LR sheet 1.

Company: PROGRESS ENERGY SERVICE COMPANY
Plant: CRYSTAL RIVER
Unit: 3
DB Name: Validation-CR3-SFA

Report Date/Time: 24-Sep-2009 10:00 am
Analysis Date/Time: 28-Jul-2009 10:53 am

CHECWORKS SFA Version: 2.2 SP-1 (build 70)

Wear Rate Analysis: Combined Summary Report

Run Name: CD CDHE-2 TO CDHE-3
Ending Period: 17R OUTAGE
Total Plant Operating Hours216776
WRA Data Option: NFA->ARD->HBD->COMP
Line Correction Factor: 0.802

Duty Factor (Global) : 1.000
Exclude Measure Wear : NO

Component Name	Geom Code	Average Wear Rate (mils/yr)	Current Wear Rate (mils/yr)	Thickness Init.	Thickness Prd.[1]	Thickness Thoop	Thickness Tcrit	Comp Predict [1] Time to Tcrit (hrs)	Inspected	Total Lifetime Wear (mils) Prd [2]	Total Lifetime Wear (mils) Meas.	In-Service Comp Wear (mils) Prd [2]	In-Service Comp Wear (mils) Meas.	In-Service Comp Tmeas. (in)[4]	Method, [3]	Time Hrs[4]	Time (hrs) Last Inspected
=== > Grouped by Line: CD-100 CDHE-2A to CDHE-3A, Sorted By: Flow Order																	
111-001 N	31	1.610	0.671	0.500	0.476	0.235	0.235	3154294	Yes	36.0	50.0	36.0	50.0	0.480	MT	169064	169064
111-002RE	16	2.176	0.906	0.375	0.321	0.235	0.235	837237	No	0.0	0.0	0.0	0.0	0.375		0	0
111-002RE (D/S)	16	3.150	1.312	0.375	0.297	0.208	0.208	591196	No	0.0	0.0	0.0	0.0	0.375		0	0
111-003P	66	2.032	0.847	0.375	0.325	0.208	0.208	1202524	No	0.0	0.0	0.0	0.0	0.375		0	0
111-004E	2	3.760	1.566	0.375	0.282	0.208	0.208	410952	No	0.0	0.0	0.0	0.0	0.375		0	0
111-005P	52	2.540	1.058	0.375	0.312	0.208	0.208	857957	No	0.0	0.0	0.0	0.0	0.375		0	0
111-006E	2	3.760	1.566	0.375	0.282	0.208	0.208	410952	No	0.0	0.0	0.0	0.0	0.375		0	0
111-007P	52	2.540	1.058	0.375	0.312	0.208	0.208	857957	No	0.0	0.0	0.0	0.0	0.375		0	0
111-008E	2	3.760	1.566	0.375	0.282	0.208	0.208	410952	No	0.0	0.0	0.0	0.0	0.375		0	0
111-009E	4	3760	1.566	0.375	0.282	0.208	0.208	410952	No	0.0	0.0	0.0	0.0	0.375		0	0
111-010P	54	3.252	1.355	0.375	0.311	0.208	0.208	662826	Yes	61.5	44.0	61.5	44.0	0.330	MT	103510	103510
111-011E	2	3.760	1.566	0.375	0.282	0.208	0.208	410952	No	0.0	0.0	0.0	0.0	0.375		0	0
111-012EE	19	4.065	1.693	0.375	0.333	0.208	0.208	641722	Yes	94.1	61.0	94.1	61.0	0.339	MT	185384	185384
111-012EE (D/S)	19	3.481	1.450	0.375	0.303	0.235	0.235	416339	Yes	80.6	102.0	80.6	102.0	0.309	MT	185384	185384
111-013N	30	3.546	1.477	0.500	0.412	0.235	0.235	1054001	No	0.0	0.0	0.0	0.0	0.500		0	0
=== > Grouped by Line: CD-101 CDHE-2B to DCHE-3B, Sorted By: Flow Order																	
108-001N	31	4.432	1.846	0.500	0.390	0.235	0.235	739138	No	0.0	0.0	0.0	0.0	0.500		0	0
108-001P	61	2.350	0.979	0.375	0.444	0.235	0.235	1870046	Yes	46.7	76.0	46.7	76.0	0.455	MT	119830	119830
108-002RE	16	2.176	0.906	0.375	0.372	0.235	0.235	1332045	Yes	43.2	54.0	43.2	54.0	0.383	MT	119830	119830
108-002RE (D/S)	16	3.150	1.312	0.375	0.389	0.208	0.208	1202251	Yes	62.6	51.0	62.6	51.0	0.404	MT	119830	119830
108-003P US	66	2.032	0.847	0.375	0.334	0.208	0.208	1299306	Yes	40.4	63.0	40.4	63.0	0.344	MT	119830	119830
108-003P DS	66	2.032	0.847	0.375	0.325	0.208	0.208	1202524	No	0.0	0.0	0.0	0.0	0.375		0	0
108-004E	2	3.760	1.566	0.375	0.282	0.208	0.208	410952	No	0.0	0.0	0.0	0.0	0.375		0	0
108-005P	52	2.540	1058	0.375	0.312	0208	0.208	857957	No	0.0	0.0	0.0	0.0	0.375		0	0
108-006E	2	3.760	1.566	0.375	0.282	0.208	0.208	410952	No	0.0	0.0	0.0	0.0	0.375		0	0

Component Name	Geom Code	Average Wear Rate (mils/yr)	Current Wear Rate (mils/yr)	Thickness Init.	Thickness Prd.[1]	Thickness Thoop	Thickness Tcrit	Comp Predict [1] Time to Tcrit (hrs)	Inspected	Total Lifetime Wear (mils) Prd [2]	Total Lifetime Wear (mils) Meas.	In-Service Comp Wear (mils) Prd [2]	In-Service Comp Wear (mils) Meas.	In-Service Comp Tmeas. (in)[4]	Method) [3]	In-Service Comp Time Hrs[4]	Time (hrs) Last Inspected
108-007P US	52	2.540	1.058	0.375	0.312	0208	0.208	857957	No	0.0	0.0	0.0	0.0	0.375		0	0
108-007P DS	52	2.540	1.058	0.375	0.350	0.208	0.208	1168065	Yes	52.5	27.0	52.5	27.0	0.360	MT	135675	135675
108-008E	2	3.760	1.566	0.375	0.349	0.208	0.208	783691	Yes	77.7	67.0	77.7	67.0	0.364	MT	135675	135675
108-009EE	19	4.065	1.693	0.375	0.372	0.208	0.208	847779	Yes	83.9	92.0	83.9	92.0	0.389	MT	135675	135675
108-009EE (D/S)	19	3.481	1.450	0.375	0.365	0.235	0.235	786571	Yes	71.9	65.0	71.9	65.0	0.379	MT	135675	135675
108-010N	30	3.546	1.477	0.500	0.412	0.235	0.235	1054001	No	0.0	0.0	0.0	0.0	0.500		0	0

Notes:

[1] Predictions are based on last Tmeas to analysis ending period.

[2] Predictions are for the time of last known meas. wear. Can be P-to-P value depending on meas. wear method.

[3] GW = Tmeas is minimum thickness from Band, Blanket or Area Method of greatest wear
MT = Tmeas is component minimum thickness.
PW = Tmeas is Tinit - predicted wear.
US = Tmeas is user specified.

[4] If no Tmeas has been determined from measured data then Tmeas = Tinit and Time = current component installation time.
Tmeas is used to determine Predicted Thickness and Component Predicted Time to Tcrit.

RAI B.2.8-1

Background:

GALL AMP XI.M18, "Bolting Integrity," states that the program relies on the recommendations for a comprehensive bolting integrity program as delineated in NUREG-1339, which is the resolution of Generic Safety Issue 29 on bolting degradation or failure, and relevant industry recommendations such as EPRI TR-104213. NUREG-1339 states that facts from some service failures and from laboratory examinations clearly show that molybdenum disulfide is a potential contributor to stress corrosion cracking (SCC).

In LRA Appendix B, Section B.2.8, the applicant stated that the Bolting Integrity Program has an enhancement to identify and remove instances where molybdenum disulfide lubricant is allowed for use in bolting applications in specific procedures and to add a specific prohibition against use of molybdenum disulfide lubricants in the CR-3 procedure for bolted connections. The staff noted that this enhancement is in agreement with the NRC staff findings summarized in the "Conclusions" section of NUREG-1339 and Generic Letter 91-17.

Issue:

It should be clarified whether the molybdenum disulfide lubricant, which was used previously or is used currently, has caused detrimental effects on the bolting materials or not.

Request:

Describe what lubricants, which have been used in the applicant's bolting integrity program, are based on molybdenum disulfide. Clarify whether the lubricants have caused detrimental effects on the bolting materials or not. Provide justification for the applicant's evaluation of the detrimental effects including relevant operating experience.

Response

A survey of procedures and warehouse inventory at CR-3 identified that Dow-Corning Molykote G-n was maintained in stock and specified in several site procedures as a bolting thread lubricant. Vendor literature for Molykote G-n identifies it as a multi-purpose, heavy-duty lubricating paste containing a blend of molybdenum disulfide and white solid lubricants in a mineral oil. The site procedures that referenced its use included both application specific and generic maintenance procedures.

NUREG-1339 references the findings of EPRI-5769 with regard to industry evaluations of molybdenum disulfide thread lubricants. At the time of its writing, EPRI-5769 noted that application of molybdenum disulfide as a thread lubricant was widespread in the nuclear industry. EPRI-5769 documents an investigation of the effects of thread lubricants containing molybdenum disulfide, and correlates the potential for SCC with the breakdown of this material in a boric acid environment at elevated temperatures. EPRI-5769 notes that SCC is caused by a combination of (1) material, (2) stress, and (3) environment, and for a given bolting material can be avoided through control of stress and environment. For example, good housekeeping practices that control boric acid attack, elimination of leakage from borated water systems, and prompt cleanup of any primary water spills are measures presented that reduce the possibility that an aggressive environment will initiate SCC. Controlling stress levels is also beneficial, *since susceptibility to SCC decreases when stresses are reduced. It follows that the potential for SCC arising from use of molybdenum disulfide thread lubricants are limited to a specific set of adverse conditions, and past use of molybdenum disulfide thread lubricants is not invariably a precursor of degradation.*

Notably, the investigation of molybdenum disulfide bolting lubricants at CR-3 documented in the License Renewal Bolting Integrity Program was not precipitated by adverse site operating experience, but rather a review of the recommendations of NUREG-1339 and related industry documents referenced in the NUREG-1801 program description. As a result of this investigation an NCR was initiated and activities implemented to remove the allowance of this lubricant from site procedures, to remove the lubricant from stock, and to train procurement personnel regarding the prohibition of this material. An operating experience review of bolted connections, also performed in support of the License Renewal Bolting Integrity Program, identified no instances of failed bolting or bolted connections at CR-3 attributed to cracking due to SCC.

RAI B.2.8-2

Background:

In LRA Appendix B, Section B.2.8, the applicant stated that the Bolting Integrity Program has enhancements for the program elements, Parameters Monitored/Inspected and Detection of Aging Effects. The applicant stated that the enhancements are to perform periodic ultrasonic examination of a representative sample of bolting identified as potentially having actual yield strength > 150 ksi. During the AMP audit, the applicant agreed that the yield strength criterion should be corrected from "> 150 ksi" to "≥ 150 ksi" in a manner consistent with the recommendation of NUREG-1339.

Issue:

GALL AMP XI.M18 indicates that high strength low alloy steel with the actual yield strength ≥ 150 ksi may be subject to SCC. The "Conclusions" section of NUREG-1339 recommends that the yield strength criteria for categorization of material's SCC susceptibility should be based on actual measured yield strength (or yield strength determined by conversion of measured hardness values), but not on the specified minimum yield strength in material specifications. One method to verify actual yield strength is to refer to the test data of Certified Material Test Reports. Based on foregoing information, the staff found a need to clarify the applicant's approach related to this topic.

The staff noted that on-site program document, L07-0372, "License Renewal Aging Management Review for the Reactor Building," Revision 2, Section 6.3.14.14, "Threaded Fasteners," addressed a calculation of the maximum yield strength using the specified minimum yield strength and specified maximum and minimum tensile strength values as described on Page 67 in relation with categorization of materials in terms of SCC susceptibility. This calculation suggests that the applicant might use specified yield and/or tensile strength values to calculate yield strength and the calculated yield strength might be used as input for SCC susceptibility categorization of materials.

Request:

Describe how the yield strength of the bolting materials will be determined as input for the yield strength criterion to categorize the materials in terms of SCC susceptibility (For example, based on actual measured yield strength, conversion of actual measured hardness, Certified Material Test Reports or specified values of yield strength, tensile strength and/or hardness in material specifications).

Response

CR-3 will consider bolting with actual measured yield strength (or yield strength determined by conversion of measured hardness values) of ≥ 150 ksi to be high strength bolting for the purposes of the Bolting Inspection Program. In the absence of actual measured yield strength data, bolting specified in the range considered medium strength by NUREG-1339 (i.e., bolting with $120 < S_y < 150$ *ksi) and above will be assumed to be high strength bolting. These bolts will be subject to sampling based inspection/testing at a 10 year frequency under the Bolting Integrity Program to verify that cracking has not occurred.*

This response involves a change to the LRA, as discussed in Enclosure 2, and to License Renewal Commitment #5 as indicated in Enclosure 3.

RAI B.2.8-3

Background:

LRA Appendix B, Section B.2.8, and onsite program documentation indicated that the program enhancements will use "EPRI-5067" (EPRI NP-5067, Volumes 1 and 2) as guidance for torquing and closure requirements and as a basis to develop a centralized procedure for joint leak tightness and pre-installation inspections.

Issue:

GALL AMP XI.M18, "Bolting Integrity," refers to EPRI NP-5769 and EPRI TR-104213 as guidance for industry recommendations. The staff also noted that EPRI NP-5769 Volume 1, Section 2 (Page 2-8) states that EPRI NP-5067 "will serve as a repository of useful information learned from EPRI experimental and analysis programs and will give the utility industry guideline." EPRI NP-5769 also states that "It is believed that the bolting reference manuals [NP-5067, Volumes 1 and 2] will satisfy the industry's need for guidance in this area." However, EPRI TR-104213, Section 1.1, indicates that the development objectives for TR-104213 were to update and consolidate the existing information (including NP-5067 and NP-6316) into a single document and to provide additional information necessary to allow a seamless integration of the material. The staff also noted that NUREG-1339 takes some exceptions for safety related bolting to EPRI NP-5769 such as yield strength criteria for categorization of materials in terms of SCC susceptibility.

Request:

Clarify whether EPRI NP-5769 with the exceptions noted in NUREG-1339 and EPRI TR-104213 will be considered and used as industry recommendations for the applicant's enhancements as well as EPRI NP-5067 that the applicant is currently planning to use. If necessary, describe how the final safety analysis report (FSAR) supplement in LRA Appendix A, Section A.1.1.8 will be revised.

Response

CR-3 will utilize EPRI NP-5769 (with the exceptions noted in NUREG-1339) and EPRI TR-104213 in addition to EPRI-5067 as guidance for torquing and closure requirements and as a basis to develop a centralized procedure for joint leak tightness and pre-installation inspections. Enhancement (4) in the FSAR supplement in LRA Appendix A, Section A.1.1.8 will be revised to state: "guidance for torquing and closure requirements based on the recommendations of EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," (with exceptions noted in NUREG-1339), EPRI TR-104213, "Bolted Joint Maintenance & Applications Guide," and EPRI 5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Personnel," Volumes I and II."

This response involves a change to the LRA, as discussed in Enclosure 2, and to License Renewal Commitment #5 as indicated in Enclosure 3.

RAI B.2.9-1

Background:

The applicant stated in Section B.2.9 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of the GALL Report, Section XI.M19, "Steam Generator Tube Integrity." It further stated that its program meets the intent of NEI 97-06 as recommended by the GALL Report.

Issue:

CR-3 program document, Nuclear Generation Group, L08-0634, describes the steam generator tube integrity aging management program. The aging management program indicates the program is consistent with the GALL Report with no exceptions. The GALL Report indicates to effectively manage the effects of aging that a licensee must, in part, implement the steam generator degradation management program described in Nuclear Energy Institute (NEI) 97-06, "Steam Generator Program Guidelines." Revision 1 of these guidelines is referenced in the GALL Report, whereas the application references Revision 2 of NEI 97-06.

Request:

Please justify the use of Revision 2 of NEI 97-06.

Response

The staff issued Revision 1 of the GALL Report in September 2005. In the program description, the staff does not identify the revision number for NEI 97-06. However, the GALL AMP XI.M19 reference section identifies NEI 97-06, Revision 1. NEI 97-06, Revision 2, was issued in May 2005. NEI 97-06, Revision 2, was not included in the GALL AMP XI.M19 reference section.

On October 3, 2005, the staff sent a letter to NEI concerning NEI 97-06, "Steam Generator Program Guidelines," Revision 2 (ADAMS Accession Number ML052780111). The staff stated that NEI 97-06, Revision 2, is consistent with Technical Specification Task Force Traveler (TSTF) 449, Revision 4, "Steam Generator Tube Integrity." The staff approved TSTF 449, Revision 4, in May 2005 and published the Traveler in the Federal Register on May 6, 2005.

In the letter dated October 3, 2005, the staff stated the following:

> *As you know, TSTF 449 and NEI 97-06 are performance based. As a result, we will continue to monitor steam generator performance at each plant consistent with our review and oversight processes. If we identify any issues with NEI 97-06 or the associated Electric Power Research Institute (EPRI) guidelines as a result of these activities, we will notify you or your staff so that you can evaluate the need to update your guidance documents.*

The GALL AMP XI.M19 states that a licensee's plant Technical Specifications, its response to GL 97-06, and its commitment to implement the steam generator degradation management program described in NEI 97-06 are adequate to manage the effects of aging on the steam generator tubes, plugs, sleeves, and tube supports.

On May 25, 2006, CR-3 submitted License Amendment Request #264 (ADAMS Accession Number ML061500062). The proposed amendment would revise the Crystal River Unit 3 (CR-3) Improved Technical Specification (ITS) requirements related to steam generator tube integrity. This submittal was consistent with NRC-approved Revision 4 to Technical Specification Task Force (TSTF) Standard Technical Specification Change Traveler TSTF-449, "Steam Generator Tube Integrity."

On May 16, 2007, The Commission issued Amendment No. 223 to Facility Operating License for CR-3 (ADAMS Accession Number ML071340112) that consisted of changes to the existing Technical Specifications. The amendment revised the steam generator tube surveillance program to one modeled after Technical Specification Task Force (TSTF) Traveler TSTF-449, "Steam Generator Tube Integrity."

In summary:

- *The staff has reviewed and approved TSTF 449, Revision 4.*
- *The staff has acknowledged that TSTF 449 and NEI 97-06 are performance based.*
- *The staff will continue to monitor steam generator performance at each plant consistent with their review and oversight processes.*
- *If the staff were to identify any issues with NEI 97-06 or the associated Electric Power Research Institute (EPRI) guidelines as a result of these activities, the staff would notify the industry so that an evaluation could be made of the need to update the guidance documents.*
- *CR-3 has amended its Technical Specifications in accordance with TSTF 449, Revision 4.*
- *CR-3 has incorporated the guidance in NEI 97-06, Revision 2, which includes the latest industry OE.*

Based on this review, the Steam Generator Tube Integrity Program, as described in Section B.2.9 of the LRA, is consistent with program elements of the GALL AMP XI.M19 while referencing NEI 97-06, Revision 2.

RAI B.2.9-2

Background:

The applicant indicated that the steam generator tube integrity program at CR-3 meets the intent of NEI 97-06 as recommended by the GALL Report.

Issue:

During the review of the CR-3 steam generator tube integrity program, numerous potential discrepancies within the same procedure, between different procedures, between the CR-3 procedures and various industry guidelines (referenced in NEI 97-06), and between the procedures and the technical specifications were identified. These issues are discussed below:

- In Section 3.1.1 of EGR-NGGC-0208, accident-induced leakage is defined, in part, as the primary-to-secondary leakage that occurs during postulated accidents when tube structural integrity is assumed. Although this definition is consistent with NEI 97-06, accident induced leakage should simply include all primary-to-secondary leakage prior to the accident and any additional leakage induced as a result of the accident (regardless of whether structural integrity is maintained). The technical specifications and bases (that were provided in the license amendment that adopted TSTF-449) do not include the "exception" that accident induced leakage does not include leakage as a result of loss of structural integrity.

- In Section 3.1.4 of EGR-NGGC-0208, it is indicated that condition monitoring is performed at the conclusion of each operating cycle. Although this frequency is consistent with NEI 97-06, it is not consistent with your technical specifications (5.6.2.10.a). The staff notes that this definition is also inconsistent with a similar definition in Section 3.3.3 of SP-305. The staff further notes that the technical specifications require condition monitoring following an outage in which inspections are performed or tubes are plugged or repaired.

- In Section 8.2.3 of EGR-NGGC-0208, it was indicated that changes in design parameters shall be assessed and included in the assessment of structural limits if they result in a primary-to-secondary pressure difference that is greater than the established value for normal operation by more than 50 pounds per square inch. Since the technical specifications require maintaining a margin of 3 against the normal operating differential pressure, it is not clear that the technical specifications would be satisfied if this procedural step were followed.

- In Section 8.4.3 of EGR-NGGC-0208, it is indicated that the pressure and temperature conditions used in the determination of the primary-to-secondary leakage rate shall be consistent with the guidance in the industry's primary-to-secondary leak guidelines. The acceptability of the leakage rate limits in your technical specifications and licensing basis were evaluated for a specific set of conditions. It is not clear that the industry's primary-to-secondary leakage guidelines require using the pressure and temperature conditions assumed in the design and licensing basis. This could result in calculating a leakage rate under one set of conditions and comparing it to limits that assumed a different set of conditions, which would not be appropriate.

- Section 9.5.6 of EGR-NGGC-0208 indicates that if the condition monitoring results are not as expected and/or growth rates are larger than expected, one or more tubes may fail to satisfy the performance criteria may fail to meet the performance criteria prior to the next inspection. The procedure then indicates remedial actions (e.g., limiting the length of inspection interval) can be taken. To ensure compliance with the technical specifications, if one or more tubes may fail to meet the performance criteria, remedial actions must be taken.

- Section 9.6.4.2 of EGR-NGGC-0208 indicates (appropriately) that leakage from all sources (e.g., plugs) must be assessed. Section 9.6.4.4 of EGR-NGGC-0208 indicated that if projected degradation is not calculated to penetrate the tube wall and projected worst case end-of-cycle degradation is not calculated to tear through the wall at accident pressure differentials there is no projected operational assessment leakage. Since primary-to-secondary leakage may occur as a result of leakage past plugs without penetrating the wall or tearing through the wall, it appears that Section 9.6.4.4 of EGR-NGGC-0208 could lead to a wrong conclusion regarding compliance with the technical specifications.

- Section 9.6.8 of EGR-NGGC-0208 indicates that if one or more tubes fail to meet the structural or accident induced leakage performance criteria prior to the next outage a condition report should be generated. It is not clear from this section (unlike other sections) that leakage from all sources would be summed to ensure that the accident induced leakage performance criteria is satisfied.

- Section 9.6.9 of EGR-NGGC-0208 indicates that if leakage causes a forced outage, then a condition report would be generated to ensure a root cause analysis for failing to meet the criteria is performed. It is not clear why a root cause evaluation would only be performed when the "criteria" (presumably the operating leakage performance criteria) is not satisfied. The industry's integrity assessment guidelines would normally require an evaluation when the leakage exceeds what is predicted (i.e., the previous operational assessment did not bound what was observed).

- Section 9.9.10 of EGR-NGGC-0208 indicates, in part, that if visual damage of the tubes is detected or considered likely that you should "determine and document the need for tube integrity assessment." This appears contradictory to the requirements of the Integrity Assessment guidelines (referenced by NEI 97-06) which indicate tube integrity shall be evaluated when tube damage is detected or considered likely.

- Section 3.3.1 of SP-305 defines alternate repair criteria different than Section 3.1.2 of EGR-NGGC-0208. The latter indicates that alternate repair criteria can be implemented if approved by the NRC (which is correct) while the former does not have this stipulation.

- Section 3.6.5 of SP-305 indicates that welded plugs showing signs of leakage are unacceptable and shall be evaluated for repair, replacement, or acceptable for continued service. It is not clear how an unacceptable plug could be considered "acceptable" for continued service.

- Section 8.4.4 indicates that the measurement and detection methods and associated actions shall adhere to the intent of the industry's primary-to-secondary leak guidelines. The reason for not fully implementing the primary-to-secondary leak guidelines (e.g., the sampling frequency requirements) is not clear.

- Section 3.3.5 through 3.3.9 and Section 3.3.21 of SP-305, terms are defined that were previously defined in technical specifications. Although some of these are consistent with definitions in the EPRI guidelines, they are no longer used in the technical specifications. In addition, not all of these terms appear to be used in the guidelines or in your procedures.

- Section 3.6.3 of SP-305 indicates that the steam generators shall be determined operable after plugging or repairing all tubes exceeding the plugging/repair limit. This was appropriate under the previous version of your technical specifications; however, the current version of your technical specifications also requires tube integrity to be maintained. As a result, the condition cited in your procedures is not sufficient for ensuring operability.

- Section 4.2.3 of SP-305 indicates that the inspection scope should be expanded, in part, per the technical specifications. The technical specifications no longer have specific guidance on expanding the number of tubes inspected.

- Section 3.6.1 of SP-305 lists five criteria for when tubes can be returned to service. At least one of the criteria must be satisfied for the tubes to be returned to service. One of these criteria is that the tubes have adequate margin against burst under normal full power and postulated accident conditions. This criterion must be satisfied for a tube to be returned to service (regardless of whether the tube meets any one of the other four criteria). Since the technical specifications require all tubes have adequate structural integrity, which includes burst and collapse, under a variety of operating conditions and that the steam generator has adequate leakage integrity, it is not clear whether these conditions are fully appropriate.

- Section 3.6.2 of SP-305 indicates that the tubes not inspected during the periodic inspection shall be considered acceptable to return to service provided the minimum inspection percentage including any required sample expansion has been met. Since the technical specifications require tube integrity to be maintained, it does not appear appropriate to just assume that because the minimum sample size was met that tube integrity would be maintained (e.g., growth rate larger than anticipated in operational assessment).

- Sections 3.6.6 and 3.6.7 of SP-305 addresses, in part, implementation of the accident induced leakage performance criteria. In Section 3.6.6 it indicates, in part, that the limit is one gallon per minute minus 150 gallons per day per steam generator. In Section 3.6.7, it indicates that the criterion is 0.699 gallons per minute. These numbers do not appear consistent. The staff also notes that leakage during normal operation may increase during design basis accidents and, therefore, simply subtracting the normal operating leakage limit of 150 gallons per day from the one gallon per minute steam line break leakage limit may not be appropriate.

- Section 4.2.3 of SP-305 indicates that eddy current data should be analyzed in accordance with the EPRI Pressurized Water Reactor Steam Generator Examination Guidelines. These guidelines do not really have sufficient information to analyze eddy current data. There are eddy current data analysis guidelines that appear to be used at CR-3, but these are not referenced in this procedure. In addition, these guidelines do not appear to be current since they reference outdated versions of the Pressurized Water Reactor Steam Generator Examination Guidelines. NEI 97-06 requires licensees to modify their steam generator programs when new guidance is issued (within the time limits specified in the transmittal letter for the new guidelines).

- Section 4.3.1 of SP-305 implies that the only tubes that require plugging are defective tubes, tubes identified during a bubble test, or tubes that exceed the repair criteria. Since there may be instances where these conditions are not satisfied but yet the tubes are required to be plugged to ensure tube integrity is maintained, it is not clear that your procedures will ensure compliance with your technical specifications.

- Section 4.3.1 of CP-152 directs the operator to go to Section 4.8 if RM-A12 is unavailable to quantify primary-to-secondary leakage and the leak rate is greater than or equal to 75 gallons per day. Section 4.8 does not appear to address the condition when RM-A12 is unavailable and therefore the plant would not be required to be in Mode 3 within 6 hours. This is a mandatory item of the PWR Primary-to-Secondary Leak Guidelines (referenced in NEI 97-06). Similarly, Section 4.3.3 directs the operator to go to Section 4.7 under specific conditions; however, Section 4.7 does not appear to address the condition when RM-A12 is unavailable.

- The PWR Primary-to-Secondary Leak Guidelines (referenced in NEI 97-06) requires increased grab sampling frequency when Action Level 1 is reached. CP-152 does not appear to require increased grab sampling frequency when this Action Level is reached rather it appears to require the same sampling as was required when the leakage was slightly less than Action Level 1 levels.

- The PWR Primary-to-Secondary Leak Guidelines requires that the method used to monitor the rate of increase in leakage for Action Level 2 shall be specified. In Section 4.7.1 of CP-152, it appears that a specific method is chosen and it is tied to a specific monitor (RM-A12). This section of CP-152 is also referenced when RM-A12 is unavailable. As a result, the method for monitoring the rate of increase does not appear to be specified in cases where RM-A12 is unavailable.

- The Steam Generator Integrity Assessment Guidelines (referenced in NEI 97-06) indicate that the degradation assessment shall include secondary side considerations such as foreign object search and retrieval. The degradation assessment for the replacement steam generators (June 2009) does not appear to address secondary side activities. Loose parts (foreign objects) have been found on the secondary side of replacement steam generators.

- The Steam Generator Integrity Assessment Guidelines indicate, in part, that the limiting structural integrity performance criteria and the appropriate loading conditions for the degradation of interest shall be identified in the degradation assessment. In addition, these guidelines indicate that the condition monitoring and operational assessment limits for all existing and potential degradation mechanisms and the appropriate measurement parameter for each degradation mechanism be identified in the degradation assessment. This information does not appear to be in the most recent degradation assessment for your current steam generator.

- The Steam Generator Integrity Assessment Guidelines indicate, in part, that projections of leakage at normal operating conditions shall be performed in the operational assessment. This information does not appear to be in the operational assessment.

- In Section 3.1 titled, "From NEI-06" of the applicant's document EGR-NGCC-0208, some definitions in the NEI 97-6 Revision 2 document "Steam generator program guidelines" do not appear, such as "collapse" or "repair methods". Furthermore, the applicant gave definitions that appear to have come from the NEI 97-06 guidelines but are not defined in this document, such as "Degradation-specific repair criteria", "Faulted", etc...

- NEI 97-06 is referenced in the GALL Report for the steam generator tube integrity program and constitutes the basis of the applicant's procedures to manage the steam generator tube integrity program. These gaps could induce some confusion in the procedures used by the applicant in order to follow the NEI guidelines, particularly for inspections, and thus manage the aging effects of steam generator tubes.

- In Section 5.3.6 of the document "Eddy current data analysis guidelines for the once-through steam generator inservice inspection", the applicant stated that "a recent site-specific data analysis performance demonstration (SSPD) performed at a similar design plant may be accepted in lieu of all or portion of the CR-3 SSPD". The EPRI document "Examination guidelines" specifies in Section G.4.3.1.1 relative to SSPD examinations that "a written test evaluates knowledge of the specific plant SG history and conditions, examinations techniques, expected damage mechanisms, and unique challenges to examination process".

- It is not obvious that another plant would have identical history, conditions, and challenges to the examination process to CR-3 to permit use of the SSPD from the other plant.

Request:

Given the number of potential discrepancies, discuss your plans to perform a comprehensive review of your steam generator program to ensure the procedures are internally consistent, will ensure compliance with the technical specifications, and are consistent with NEI 97-06.

Response

The Steam Generator Tube Integrity Program is defined as an "Engineering Program" per corporate procedure. As such, the program is reviewed on a frequency not to exceed two years. The most recent assessment (March 2008) concluded that the program met the requirements of the Technical Specifications. This review process will ensure that the procedures are internally consistent and compliant with the technical specifications, and are consistent with NEI 97-06.

RAI B.2.9-3

Background:

The applicant stated in Section B.2.9 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of the GALL Report, Section XI.M19, "Steam Generator Tube Integrity." It further stated that its program meets the intent of NEI 97-06 as recommended by the GALL Report.

Issue:

During the review of CR-3 program document, EGR-NGGC-0208, a definition of faulted was provided which indicates it only includes secondary side depressurizations. The reason for restricting this definition to only secondary side depressurizations is not clear. Since it is not evident how this definition is used in the steam generator program, unnecessarily restricting this definition to one class of design basis accidents may be inappropriate (and result in not meeting regulatory requirements).

Request:

Please discuss how the term "faulted" is used in the program and, if it is used, discuss the reason for only limiting the definition to secondary side depressurizations.

Response

This definition is not part of NEI 97-06, Revision 2. A procedure revision request has been generated to remove it from the corporate procedure. As stated in the response to RAI B.2.9-2, the program review process will ensure that the procedures are internally consistent and compliant with the technical specifications, and are consistent with NEI 97-06.

RAI B.2.9-4

Background:

The applicant stated in Section B.2.9 of the LRA that its Steam Generator Tube Integrity program is an existing program that is consistent with the recommendations of the GALL Report, Section XI.M19, "Steam Generator Tube Integrity." It further stated that its program meets the intent of NEI 97-06 as recommended by the GALL Report.

Issue:

Section 9.7 of EGR-NGGC-0208 indicates tube plugging will be performed to industry standards. This reference is not clear. In addition, the Inservice Inspection Program Plan (dated December 21, 2007, 3F11207-04) does not appear to address steam generators. 10 CFR 50.55a requires, in part, that Section XI of the ASME Code be followed with certain exceptions. Section XI of the ASME Code addresses, in part, steam generator tube plugging and inspections and performance of non-destructive examinations. For steam generators, there is an exception in 10 CFR 50.55a that if the technical specification surveillance requirements are different than those in the ASME Code then the technical specifications govern. Since the technical specifications do not address all aspects of steam generator inspection and maintenance (e.g., plugging), the lack of reference to the ASME Code in the steam generator program raises questions on whether the requirements of the ASME Code are being met.

Request:

Please confirm that the ASME Code requirements pertaining to steam generator tube plugging, sleeving, and non-destructive examination are being followed (for those instances where there is no conflict with the specific requirements in the technical specifications).

Response

The ASME Code requirements pertaining to steam generator tube plugging, sleeving, and non-destructive examination are being followed (for those instances where there is no conflict with the specific requirements in the technical specifications).

RAI B.2.9-5

Background:

In Sections 4.1.1 and 4.1.2 of the document SP-305 "Once-Through Steam Generator Inservice inspection" relative to visual inspection of tube plugs, the applicant used the expression "PGN approved procedures" without referencing these procedures in this document.

Issue:

It isn't clear which procedures should be applied according to the document SP-305.

Request:

Please identify the specific PGN procedures discussed in SP-305.

Response

The procedures referenced are vendor's procedures that must be approved by PGN prior to their use.

RAI B.2.10-1

Background:

The applicant states that its LRA AMP Open Cycle Cooling Water System (B.2.10) is consistent with the GALL AMP, Open Cycle Cooling Water System (XI.M20). In its audit of program Element 4 (acceptance criteria), the staff identified a potential inconsistency between the LRA AMP and the GALL AMP.

Issue:

LRA AMP program Element 4, detection of aging effects, contains inspections techniques typically employed by Generic Letter 89-13 and which are consistent with the corresponding element in the GALL AMP. Section 7.5 of the applicant's document L08-0613, "License Renewal Aging Management Program Description of the Open Cycle Cooling Water System Program" indicates that, in addition to its normal uses, the LRA AMP will be used to detect selective leaching. The selective leaching AMP utilizes both visual inspection techniques and hardness/scratch tests to identify selective leaching. It is not clear to the staff that the LRA AMP will adequately detect selective leaching unless it is enhanced to include some form of hardness testing.

Request:

Justify the exclusion of hardness testing for the identification of selective leaching or justify how this aging effect may be identified using the inspection techniques already specified.

Response

An enhancement to the Open Cycle Cooling Water System AMP has been added to perform hardness/scratch testing for selective leaching for susceptible valves and pumps. Examination of Nuclear Services Closed Cycle Cooling Water Heat Exchangers heat exchanger tubesheet cladding will consist of visual inspection for discoloration/evidence of degradation (consistent with operating experience regarding how the aging effect was initially noted), supplemented by hardness/scratch testing if discoloration/evidence of degradation is detected.

This response involves a change to the LRA, as discussed in Enclosure 2, and to License Renewal Commitment #6 as indicated in Enclosure 3.

RAI B.2.10-2

Background:

The applicant states that its LRA AMP, Open Cycle Cooling Water System (B.2.10), is consistent with the GALL AMP, Open Cycle Cooling Water System (XI.M20). In its audit of program Element 6 (acceptance criteria), the staff identified a potential inconsistency between the LRA AMP and the GALL AMP.

Issue:

Section A.1.2.3.6 of the Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants (SRP-LR) states that the program element "acceptance criteria" should contain information concerning the acceptance criteria against which the need for corrective action will be measured. This section of the SRP-LR also states that the acceptance criteria should consist of numerical values or methods by which they are determined. The staff notes that this information is absent from this section of the LRA AMP. In order for the staff to evaluate the consistency of this LRA program element with the corresponding GALL Report program element, it is necessary that the applicant provide this information in the LRA AMP.

Request:

Please provide acceptance criteria as indicated in the SRP-LR.

Response

An enhancement has been added to the Open Cycle Cooling Water System AMP to incorporate applicable acceptance criteria into program activities for inspection for biofouling and maintenance of protective linings. Acceptance criteria will be added to procedures and periodic maintenance instructions to ensure: (a) removal of accumulations of biofouling agents, corrosion products, and silt, and (b) detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions.

This response involves a change to the LRA, as discussed in Enclosure 2, and to License Renewal Commitment #6 as indicated in Enclosure 3.

RAI B.2.10-3

Background:

The applicant states that its LRA AMP, Open Cycle Cooling Water System (B.2.10), is consistent with the GALL AMP, Open Cycle Cooling Water System (XI.M20). In its audit of program Element 10 (operating experience), the staff identified a potential deficiency in the LRA AMP.

Issue:

Assessment number 149036, Observation number JL06, Service Water Reliability, GL 89-13 Program Assessment indicates that the concrete lining is missing from some sections of the concrete lined, cast iron, 48 inch piping. This assessment also indicates that the sections of the piping from which the concrete is missing are not being monitored for loss of material. Since the GALL AMP is designed to manage aging for lined piping and since corrosion of unlined piping is expected to be greater than for lined piping, it is not clear that the LRA AMP will adequately manage aging for the areas of pipe without concrete lining without additional inspection or control measures.

Request:

Please justify how the LRA program will adequately manage aging in the unlined sections of piping or propose enhancements to the program which consider these piping sections.

Response

CR-3 Nuclear Services and Decay Heat Seawater System Intake Conduits will be inspected under periodic maintenance activities for degraded / missing concrete lining. Areas with degraded / missing concrete lining will be monitored to assure no loss of intended function until such time as the lining can be repaired. This response involves a change to the LRA, as discussed in Enclosure 2, and to License Renewal Commitment #6 as indicated in Enclosure 3.

RAI B.2.11-1

Background:

The CR-3 LRA proposes an exception to the GALL Report recommendation by not subjecting the closed-cycle cooling water pumps to a formal testing program. The LRA states that the ability of the systems to maintain adequate flow rates and heat transfer is verified on an ongoing basis by routine operation of the systems.

Issue:

The GALL Report recommends monitoring the following pump parameters: flow, discharge, and suction pressures as a part of system and component evaluation.

Request:

Please provide details on how the system's ability to maintain flow rates and heat transfer is to ensure without subjecting the cooling water pumps to a formal testing program. Particularly, (1) state the surrogate parameters, if any, that are being monitored as a part of system health evaluation if the GALL Report recommended parameters are not monitored, and (2) provide justification as to how the surrogated parameters could provide equivalent protection to the cooling water pumps.

Response

The Secondary Services Closed Cycle Cooling System and the Instrument Air System closed cycle cooling loop are not subjected to regular pump testing per se, but acceptable performance is verified by ongoing systems monitoring activities which verify Maintenance Rule functions are met.

Secondary Services Closed Cycle Cooling System performance monitoring includes Secondary Services Closed Cycle Cooling Pump suction and discharge pressure and flow, consistent with the recommendations of GALL.

Instrument Air System performance monitoring includes monitoring of Instrument Air header pressure and dew point. The Instrument Air System closed cycle cooling loop provides cooling water to the compressors, as well as the intercooler and aftercooler for heat and moisture removal in support of operation of the Instrument Air dryer. Therefore, adequate flow and heat transfer of the Instrument Air System closed cycle cooling loop is verified by performance monitoring of the instrument air compressors and dryers.

An enhancement has been added to the Closed Cycle Cooling Water System AMP to flag the systems monitoring procedure to identify monitoring of these Secondary Services Closed Cycle Cooling System and Instrument Air System parameters as a License Renewal requirement. The exception in the Closed-Cycle Cooling Water System AMP regarding monitoring closed-cycle cooling water system pumps applies to the use of surrogate parameters in the Instrument Air System.

This response involves a change to the LRA, as discussed in Enclosure 2, and requires a new License Renewal Commitment #29 as indicated in Enclosure 3.

RAI B.2.11-2

Background:

The CR-3 LRA proposes an exception to the GALL Report recommendation by not subjecting the closed-cycle cooling heat exchangers to a formal performance monitoring program. The LRA states that the thermal and hydraulic performance of the systems is verified on an ongoing basis by routine operation of the systems.

Issues:

The GALL Report recommends monitoring the following heat exchanger parameters: flow, inlet and outlet temperatures, and differential pressure as a part of system and component evaluation.

Request:

Provide details on how the systems' ability to maintain flow rates and heat transfer is to ensure without subjecting the cooling water heat exchangers to a formal testing program. Particularly, please state the surrogate parameters that are being monitored as a part of system health evaluation if the GALL Report recommended parameters are not monitored and provide justification as to how the surrogated parameters could provide equivalent protection to the cooling water heat exchangers.

Response

The Secondary Services Closed Cycle Cooling System and the Instrument Air System closed cycle cooling loop are not subjected to regular heat exchanger testing per se, but acceptable performance is verified by ongoing systems monitoring activities which verify Maintenance Rule functions are met.

Secondary Services Closed Cycle Cooling System performance monitoring includes Secondary Services Closed Cycle Cooling heat exchanger flow, and inlet and outlet temperatures.

Instrument Air System performance monitoring includes monitoring of Instrument Air header pressure and dew point. The Instrument Air System closed cycle cooling loop provides cooling water to the compressors, as well as the intercooler and aftercooler for heat and moisture removal in support of operation of the Instrument Air dryer. Therefore, adequate flow and heat transfer of the Instrument Air System closed cycle cooling loop is verified by performance monitoring of the instrument air compressors and dryers.

An enhancement has been added to the Closed Cycle Cooling Water System Aging Management Program to flag the systems monitoring procedure to identify monitoring of these Secondary Services Closed Cycle Cooling System and Instrument Air System parameters as a license renewal requirement. The exception in the Closed-Cycle Cooling Water System Aging Management Program regarding monitoring closed-cycle cooling water system heat exchangers applies to the use of surrogate parameters in the Instrument Air System.

This response involves a change to the LRA, as discussed in Enclosure 2, and requires a new License Renewal Commitment #29 as indicated in Enclosure 3.

RAI B.2.11-3

Background:

The CR-3 LRA states that the corrosion inhibitor concentrations stayed with the EPRI Closed Cooling Water Chemistry Guidelines with no reference to a specific version of the report. The GALL Report recommends following the guidance in EPRI TR-109376, "Closed Cooling Water Chemistry Guideline" dated 1997.

Issue:

The applicant references EPRI TR 1007820 "Closed Cooling Water Chemistry Guideline," Revision 1, dated 2004, in its plant procedures CP-160 and CH-400 as the basis for the action level limits, action responses, and sampling frequency for control and diagnostic parameters.

Request:

Please provide (1) a comparison between the CR-3 Closed Cycle Cooling Water System Program control/diagnostic parameters, associated limits, and sampling frequency to those found in the EPRI 1997 and 2004 guidelines, and (2) a justification as to why an exception to the GALL Report was not taken in the LRA if CR-3 opts to follow the 2004 version of the EPRI guideline.

Response

Like other EPRI water chemistry guidelines, the EPRI Closed Cooling Water Chemistry Guidelines is not a static document, but is subject to ongoing industry review and continual improvement. Progress Energy is committed to basing its water chemistry programs on industry best-practices and the most current industry guidelines such as the EPRI Closed Cooling Water Chemistry Guideline. Additionally, the Institute of Nuclear Power Operations (INPO) routinely examines each plant's closed cooling water chemistry programs, as well as other water chemistry programs, for comparison to the most recent EPRI guidelines and to industry best practices. There is considerable impetus for utilities to continually update their water chemistry programs to incorporate revisions to EPRI water chemistry guidelines as they are issued, and it is reasonable to assume that the industry will do so. Consistent with the treatment of the EPRI Water Chemistry Guidelines in NUREG-1801, Volume 2, Section XI.M2, CR-3 considers that Closed Cycle Cooling Water System Aging Management Program acceptability is not based on maintaining verbatim compliance with an outdated revision of the EPRI Closed Cooling Water Chemistry Guidelines through the period of extended operation. Rather, the use of later versions of the EPRI Closed Cooling Water Chemistry Guidelines meets the intent of NUREG-1801, Volume 2, Section XI.M21, and does not constitute an exception.

A comparison of the CR-3 Closed Cycle Cooling Water System Program control/diagnostic parameters to those of the current version of the EPRI Closed Cooling Water Chemistry Guidelines shows the following differences:

> *The EPRI Closed Cooling Water Chemistry Guidelines present a set of Control Parameters, which have defined limits, for closed cycle cooling water chemistry, as well as diagnostic parameters. Diagnostic parameters are generally not a direct function of corrosion inhibition and have no action levels, but can be used as a means to help*

identify the source of off-normal conditions. In some instances, CR-3 utilizes an alternate set of diagnostic parameters based on the control parameters monitored and plant-specific considerations.

The monthly sampling frequency for pH and NO_2^- in the Control Complex Chilled Water System and Appendix R Chilled Water System is monthly, rather than weekly. For Tier 1 systems, the EPRI Closed Cooling Water Chemistry Guidelines specify that weekly monitoring for pH and NO_2^- may be relaxed to monthly after all control parameters are maintained within the normal operating range for one quarter, and microbiological activity is under control. The Control Complex Chilled Water System (cools the Control Complex) and Appendix R Chilled Water System (provides normal cooling to Turbine Building Switchgear) are operated continuously, unless shut down for maintenance. The sampling frequencies for pH, NO_2^-, tolyltriazole, Fe, Cu, NH_3, and microbiological activity were evaluated based on historical CR-3 rates of change. These evaluations supported revising monitoring of pH and NO_2^- at the reduced frequency as allowed by the EPRI Guidelines.

RAI B.2.13-1

Background:

The CR-3 LRA proposes an exception to GALL AMP XI.M26 on the Halon fire suppression system testing frequency. The GALL Report recommends a 6-month inspection and testing frequency of the Halon system. The applicant proposes to test the Halon system once every 18 months during the refueling outage. The applicant states that the exception is acceptable because the Halon system is located in a conditioned air environment.

Issue:

The functional testing frequency of the Halon system does not meet the GALL recommended frequency.

Request:

Please provide:

1. Reason(s) based on the plant operating experience and other relevant details (e.g., the manner in which the air is conditioned and/or filtered to remove corrosive substances, etc.) to justify the extended functional testing frequency for the Halon system.

2. Details on any corrective/compensatory action(s) taken in the event when the air condition is out of service.

3. The Code of Record year for the NFPA 12A "Standards on Halon 1301 Fire Extinguishing Systems" for CR-3.

Response

The CR-3 Halon Fire Suppression System provides fire suppression for the Cable Spread Room. The system consists of a set of Halon tanks located in the Cable Spread Room, each of which has a short piping stub incorporating an actuation mechanism and terminating in a spray nozzle. The Cable Spread Room is located in the Control Complex, which houses the control room and instrumentation and controls for numerous systems. HVAC for the Control Complex is supplied by the Control Complex Ventilation System, which features redundant safety related trains. The Control Complex Ventilation System is required to operate to provide cooling for control room habitation, as well as equipment cooling. The system incorporates filtration to remove particulates, as well as heating coils for dehumidication. The system provides an environment consistent with the description of "indoor air – uncontrolled" in NUREG-1801 Volume 2, Chapter IX, for which no aging effects are predicted in NUREG-1801 AMR tables in Chapters V, VII & VIII.

The Code of Record for the CR-3 Halon System is NFPA 12A-1970, which specifies a 12 month frequency for inspection and testing of Halon Systems. The 18 month frequency utilized by CR-3 originates in License Amendment No. 13 to the Crystal River operating license, which incorporated Technical Specifications regarding fire protection systems and administrative controls.

RAI B.2.13-2

Background:

The CR-3 LRA proposes an exception to GALL AMP XI.M26 on the frequency of visual inspection of walls, ceilings and floors commensurate with the safety significance of the structure and its condition but not to exceed 10 years. The GALL Report recommends that visual inspections of fire barrier walls, ceilings, and floors be performed at least once every refueling outage.

Issues:

The applicant's proposed fire barrier visual inspection frequency does not meet the recommended frequency given in the GALL Report.

Request:

Please provide the basis for exceeding the GALL Report recommended frequency of inspecting the walls, ceilings, and floors.

Response

As stated in LRA Subsection B.2.13, the CR-3 Fire Protection Program performs visual inspection of walls, ceilings, and floors on a frequency commensurate with the safety significance of the structure and its condition but not to exceed ten years. Activities which implement the Structures Monitoring Program (SMP) already perform a visual inspection of walls, ceilings, and floors and examine for any sign of degradation such as cracking, loss of material (spalling), and change in material properties. The basis for the increased interval for *structural inspections is that CR-3 reinforced concrete has been acceptable during previous inspections with only minor degradation recorded in 33 years. There have been no deficiencies of the concrete fire barrier walls, ceilings, and floors which have required corrective actions for a loss of fire barrier function. After each periodic inspection of a structure, a reassessment of the structural inspection frequency is performed based on the results of the inspection. The frequency of structural inspections is increased based on the condition of the structure, which would also increase the inspection frequency for the fire barriers. The structural inspections are sufficient to detect gradual degradation of the fire barrier walls, ceilings, and floors. An enhancement has been added to the Fire Protection Program and included in the LRA to notify Fire Protection of any deficiencies having the potential to adversely affect the fire barrier function of concrete walls, ceilings, and floors to ensure corrective actions are taken.*

RAI B.2.14-1

Background:

The CR-3 LRA proposes an enhancement to "either replace the sprinkler heads prior to their 50-year service or perform field service testing of representative samples from one or more sample areas by a recognized testing laboratory. Subsequent test intervals will be based on test results." The GALL Report recommends following NFPA 25 "Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems" guidelines when replacing and or testing the sprinkler heads.

Issues:

The GALL Report recommends the subsequent testing be performed every 10 years following the initial field service testing. The 10-year testing interval is also referenced in NFPA 25 date 2002, Section 5.3.1.1.1. The applicant states the "subsequent test intervals will be based on test results."

Request:

Please provide reason(s) why it is appropriate to rely on the initial test results to schedule the subsequent sprinkler head testing instead of following the GALL Report recommendation of conducting the subsequent sprinkler head testing at a 10-year interval following the initial testing.

Response

CR-3 will perform sprinkler head testing at an interval of every 10 years following initial field service testing, consistent with the recommendations of NUREG-1801 and NFPA-25.

This response involves changes to the LRA as shown in Enclosure 2 and a change to License Renewal Commitment #9 as shown on Enclosure 3.

RAI B.2.15-1

Background:

As described in GALL AMP XI.M29, the effects of corrosion of the aboveground steel tanks are detectable by (1) periodic system walkdowns during each outage to monitor degradation of the external coating on the tank surface and the sealant at the metal-concrete interface, and (2) thickness measurement of the tank bottom to assess the underground surface condition.

Issue:

By letter dated December 15, 2008, the licensee, in commitment number 10, commits to implementing this program prior to the period of extended operation. The applicant states that tank bottom surface thickness measurement and internal visual inspections will be performed using the planned preventive maintenance activities. Although no additional thickness measurements are identified, frequency of the thickness measurements will be based on the findings of visual inspections performed. It is not clear how, and the frequency of, tank bottom thickness measurement and internal visual inspection will adequately manage the aging effects of the tanks to ensure their intended function will be maintained during the extended period of operation.

Request:

1. Clarify how internal visual inspections are adequate to exclude corrosion of underground external surface if no additional thickness measurements are performed.

2. Clarify and justify the frequency of tank bottom thickness measurement and internal visual inspection to be performed under the preventive maintenance program will adequately detect and monitor the effects of corrosion of the tank bottom surface.

Response

Since corrosion may occur at inaccessible locations, such as the tank bottom surface, thickness measurements of the tank bottom will be taken to ensure that significant degradation is not occurring. This program will include a UT inspection of the inaccessible surfaces (tank bottoms) of each of the three in-scope tanks within the 10-year period prior to entering the period of extended operation to ensure that degradation is not occurring on the external surface of the tank bottom. Inspection results that identify indications or relevant conditions of degradation will be compared to the tank design thickness and corrosion allowance. Based on the UT inspection results and industry experience, CR-3 may perform additional ultrasonic testing inspections as part of corrective actions within the plant's Corrective Action Program.

LRA Subsection B.2.15, page B-51 states:

> *For inaccessible surfaces, such as the tank bottom, thickness measurements will be performed from inside the tank to assess the tank bottom condition. Performing these inspections of tank bottoms ensures that degradation or significant loss of material will not occur in inaccessible locations. The frequency of tank bottom volumetric inspections will be based on the findings of inspections performed prior to the period of extended operation.*

The approach of a UT inspection of the inaccessible tank surfaces is considered an acceptable verification program as outlined in GALL AMP XI.M29 program description, and is consistent with the recommendations of the program element, "monitoring and trending," of GALL AMP XI.M29.

RAI B.2.16-1

Background:

In LRA Section B.2.16.2-2, the applicant takes exception to the GALL Report in that, the diesel fire pump fuel storage tank FST-2A and FST-2B are not periodically drained of water, but rather, bottom sampling of the tanks is performed quarterly to determine water buildup in the tank bottom.

Corrective actions were taken in 2009 to address an increasing trend of particulates in tanks FST-2A and FST-2B. The actions taken to address the increase in particulates included flushing, cleaning and refilling of the tanks. It was further stated in nonconformance reports (NCR) 313507 and 309256 that an ultrasonic test (UT) inspection will be performed to evaluate tank conditions and a work activity will be developed to periodically inspect the internal surfaces of the tanks.

Issue:

The LRA does not provide a clear justification for how periodic sampling for water is equivalent to the aging management program described in the GALL Report. Additionally, based on records reviewed, it is not clear whether the cause(s) of the increased particulates is or is not related to the current method of sampling.

Request:

Justify how periodic sampling for water is equivalent to the AMP described in the GALL Report. Additionally, discuss the cause(s) of the 2009 tank particulate issue and whether these are related to the tank sampling process currently employed for FST-2A and FST-2B.

<u>Response</u>

Fuel oil quality is maintained by the purchase of quality fuel and the establishment of a diesel fuel oil testing program to implement required testing of both new and stored fuel oil. The program includes sampling and testing requirements and acceptance criteria in accordance with ASTM Standards. Exposure to fuel oil contaminants, such as water and microbiological organisms, is minimized by verifying the quality of new fuel oil and the addition of a biocide, a stabilizer, and corrosion inhibitors to the fuel oil. The use of a diesel fuel stabilizer additive package containing an antioxidant, corrosion inhibitor, dispersant, and metal deactivator was initiated within the last year. CR-3 had previously been adding only a microbiocide to the diesel fuel.

The diesel fuel in the Diesel Driven Fire Pump Fuel Oil Storage Tanks FST-2A and FST-2B is sampled and analyzed quarterly. The quarterly testing parameters include viscosity, water and sediment, bottom water and sediment, particulates, specific gravity, copper strip corrosion, *oxidation stability, lubricity, and microbial growth. Continued quality levels are assured by this periodic checking for water in tanks and sampling to confirm target values. These diesel fuel analyses for FST-2A and FST-2B provide a good overall indication of fuel quality, ensure fuel break down due to long term storage has not occurred, and provide assurance that water accumulation is not occurring and that tank degradation has not occurred.*

LRA Appendix B.2.16 for the Fuel Oil Chemistry Program noted an enhancement was needed to:

> *Inspect the internal surfaces of the Diesel-Driven Fire Pump Fuel Oil Storage Tanks and develop a work activity to periodically inspect the internal surfaces of these tanks. Prior to the inspection, remove fuel, water, and sediment as much as practical due to limited access. UT or other non-destructive examination (NDE) will be performed if visual inspection proves inadequate or indeterminate.*

Performance of UT of the two tanks is no longer contingent upon whether visual inspection proves inadequate or indeterminate. New preventive maintenance periodic activities using UT and internal tank inspections have recently been generated for FST-2A and FST-2B.

Several actions have been beneficial in reducing particulates in the two tanks. Recent actions have included flushing, cleaning, and refilling the tanks. In addition, the plant has recently initiated use of a diesel fuel stabilizer containing corrosion inhibitors. Chemistry analyses records clearly indicate that the level of particulates in FST-2A and FST-2B have dropped dramatically over the last two years. FST-2A particulates were measured as high as 24 in early 2008 and recently were measured at 3. FST-2B particulates were measured as high as 19 in late 2007 and recently were measured at 3.

Based on purchasing, sampling, and testing requirements, and the use of fuel oil additives, the program ensures that significant degradation is not occurring and that the component intended function will be maintained during the extended period of operation.

RAI B.2.16-2

Background:

After the issuance of Revision 1 of the GALL Report, the NRC has issued Information Notice (IN) 2009-02, "Biodiesel in Fuel Oil Could Adversely Impact Diesel Engine Performance." This IN discusses potential issues that may occur with the use of B5 blend fuel oil, such as: suspended water particles, biodegradation of B5, material incompatibility, etc.

Issue:

The LRA did not provide information discussing the concerns of IN 2009-02 and the acceptable or unacceptable use of biodiesel at CR-3.

Request:

Provide a summary of the actions that were taken to determine the impact of IN 2009-02 and the use of biodiesel fuel oil at CR-3. If actions have not been taken yet, describe the actions that CR-3 will take to determine the impact of IN 2009-02 and the acceptable or unacceptable use of biodiesel.

If biodiesel is currently being used at CR-3, describe any problems that CR-3 encountered with the use of biodiesel and the associated corrective actions to prevent reoccurrence in the future.

If biodiesel has been determined to not be acceptable for use at CR-3, describe the actions taken and/or will be taken to prevent its addition into fuel oil supply. Also describe actions that will be taken if it is determined that biodiesel has been added into the fuel oil supply.

Response

Biodiesel is not being used at CR-3. Progress Energy utilizes a Common Diesel Fuel Oil (Grade 2-D) Testing Specification in controlling the purchase of new diesel fuel for its nuclear fleet. This specification states that due to the increasing potential of No. 2 diesel fuel oil containing a blend of biodiesel, prudent precautions shall be taken to ensure that no biodiesel fuel is accepted, even when mixed with any Grade 2-D diesel fuel. IN 2009-02 was considered as an input in the recent revision of this fuel oil specification. The specification also states that testing shall be conducted prior to fuel delivery to verify the absence of biodiesel in No. 2 diesel fuel oil using test method ASTM D7371-07. The specification identifies that new diesel fuel oil will be pre-offload tested so that the maximum amount of biodiesel is 1.0% by volume. This test is required to be satisfactorily completed prior to offloading the diesel fuel into the CR-3 fuel oil storage tanks.

RAI B.2.19-1

Background:

The CR-3 LRA Section B2.19, Selective Leaching of Materials Program, states that it is consistent with GALL AMP XI.M33, which includes the AMP's 10 elements (with one exception).

Issue:

GALL AMP XI.M33, Operating Experience element, states that the elements that comprise these one-time inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and staff expectations. Industry has identified a number of instances attributed to selective leaching that may be applicable to the CR-3 AMP. LRA Section B.2.19 addresses CR-3 plant specific operating experience and Calculation No. L08-0625, "License Renewal Aging Management Program Description for Selective Leaching of Materials Program," Revision 1, identifies experience at other Progress Energy plants, but does not address other industry experience and practices beyond Progress Energy-specific examples for the staff to evaluate the acceptability of the AMP.

Request:

For AMP B.2.19 provide additional description of the industry operating experience searched and reviewed and how it will be implemented or utilized for the basis and actions of the CR-3 Selective Leaching AMP. Also provide specifics as to data bases, sources and documents searched, key search terms, and time periods.

Response

The development of the CR-3 License Renewal Application extensively incorporated consideration of both site and industry operating experience to identify applicable aging effects and verify the effectiveness of aging management programs. Progress Energy License Renewal procedures directing aging management reviews state:

> *All methods of identifying aging effects shall be augmented by a review of site and industry operating experience. The purpose of this review is to validate the results of aging effect evaluations and identify any additional aging effects based on operating history.*

Initially, it is noted that industry operating experience was incorporated into the basis documents utilized in development of the LRA. CR-3 aging management review development utilized Revision 4 of the EPRI Non-Class 1 Mechanical Implementation Guideline and Mechanical Tools, consistent with aging management review methodology discussed in NEI 95-10. The EPRI report documents an extensive review of industry operating history, and specifically includes operating experience associated with selective leaching. The report summary within the EPRI tools document, published January 2006, states:

> *EPRI published Revision 2 of the B&W report (TR-114882) as a set of Mechanical Tools for use by utilities in preparing license renewal submittals. This fourth revision of the Mechanical Tools incorporates changes that bring the document in line with current industry practices and recent operating experience, and includes comparison of the results to information contained in Volume 2 of NUREG-1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report – Tabulation of Results."*

Notably, the CR-3 aging management review methodology, based on the EPRI tools document, predicts selective leaching as an applicable aging effect for susceptible materials in all raw and treated water environments.

CR-3 extensively utilized NUREG-1801 in the development of aging management reviews, including comparison of aging management review results against those identified in NUREG-1801, Volume 2, AMR tables. Additional sources of operating experience relative to development and verification of aging management program effectiveness are found in the Volume 2 program descriptions. As noted in NEI 95-10:

> *NUREG-1801 is based upon industry operating experience prior to its date of issue. Operating experience after the issue date of NUREG-1801 should be evaluated and documented as part of the aging management review.*

Progress Energy procedures directing system/component monitoring and trending require that system health reports be maintained, and that periodic updates be performed to capture relevant plant and industry operating experience, regulatory correspondence, technical issues, etc. System Heath reports were reviewed for relevant operating experience in the development of aging management reviews to ensure that the set of aging effects identified was comprehensive. Notably, several instances of selective leaching were identified at CR-3 which impacted aging management reviews, in that components that had been identified as having selective leaching in their operating experience were not included in the Selective Leaching

Program for one-time examinations, but rather were subject to periodic examinations in alternate aging management programs.

Progress Energy procedures direct an ongoing review of operating experience and require that operating experience be screened and evaluated for site applicability. Operating experience sources reviewed under this procedure include INPO and WANO OE items (EARs, ENRs, JITs, SENs, SERs, SOERs and SOs), NRC documents (INs, Generic Letters, Notices of Violation, and staff reports), 10 CFR 21 Reports, and vendor bulletins, as well as corporate internal OE information from all Progress Energy nuclear sites. Operating experience screened as applicable is captured in the Corrective Action Program for follow-up and resolution. CR-3 aging management review methodology incorporated a review of operating experience items identified as applicable to CR-3, addressing a review of at least the prior five to ten years, consistent with the recommendations of NEI 95-10. These searches were facilitated by CR-3 License Renewal database queries using key words that would be effective in identifying the appropriate aging effects and mechanisms.

As noted in NUREG-1801, Volume 2, XI.M33, the Selective Leaching Program is a new one-time inspection program to be applied by the applicant, and is consistent with industry practice and staff expectations. While operating experience is not currently available to gauge the effectiveness of this new program, sufficient consideration was given to operating experience in the aging management review process to ensure the scope of the program is comprehensive, and that aging management activities will address components potentially susceptible to selective leaching such that their intended functions are not compromised during the period of extended operation.

RAI B.2.19-2

Background:

The CR- 3 LRA Section B.2.19, Selective Leaching of Materials Program, states that the program is consistent with GALL AMP XI.M33, which includes the AMP 10 elements (with one exception).

Issue:

GALL AMP XI.M33, Program Description, identifies brackish water as an environment that the AMP is intended to address. The applicant's LRA Section B.2.19 and the supporting calculation number L08-0625, "License Renewal Aging Management Program Description for Selective Leaching of Materials Program," Revision 1, identify a number of water environments as being applicable to this AMP, but does not specifically identify brackish water as one of the environments.

Request:

For AMP B.2.19, verify that the identified environments do or do not envelope a brackish water environment; and, if not, provide the technical basis for not considering brackish water.

Response

Table 3.0-1 of the CR-3 License Renewal Application lists service environments considered in development of aging management reviews. The description of the Raw Water environment shows this environment encompasses a range of untreated water sources, including seawater from the Gulf of Mexico. The CR-3 intake canal is physically located considerably north of the outlet of Crystal River such that the intake water is essentially seawater. Nonetheless, to the extent that fresh water might mix with seawater and be introduced into CR-3 cooling water intake, it is enveloped within the "Raw Water" environment. From the standpoint of predicting aging effects, all sources of raw water are assumed to be capable of initiating selective leaching in susceptible materials.

RAI B.2.20-1

Background:

The LRA states that the Buried Piping and Tanks Inspection Program (B.2.20) is consistent with the GALL AMP, Buried Piping and Tanks Inspection (XI.M34). In its audit of program Element 4 (detection of aging effects), the staff identified a potential inconsistency between the LRA AMP and the GALL AMP.

Issue:

Section A.1.2.3.4 of the SRP-LR states that the program element "detection of aging effects" should contain information concerning the frequency, extent, sample size and methods used to detect aging. The staff notes that much of this information is absent from this section of the LRA AMP. In order for the staff to evaluate the consistency of this LRA program element with the corresponding GALL Report program element, it is necessary that the applicant provide additional information concerning the program for detection of aging effects.

Request:

Please provide additional details of the proposed inspection program.

Response

Since the Buried Piping and Tanks Inspection Program is a GALL program, the AMP is responsive to the criteria for an acceptable program in NUREG-1801, Volume 2, Section XI.M34. The inspection frequency of buried piping will depend heavily on opportunistic maintenance and modification activities. There will be at least one opportunistic or focused buried piping inspection performed within the ten year period prior to the period of extended operation. There will also be at least one buried piping inspection performed every 10 years during the period of extended operation. Procedural guidance will direct the inspection of underground piping within the scope of License Renewal when it is exposed for maintenance or for any reason.

The extent of methods used to detect aging will include visual inspections. Applicable attributes for visual inspections include, but are not limited to: intact protective coating, no holidays, no indication of corrosion underneath, no appreciable settlement that could cause pipe stress, no *signs of separation, no leakage, and no sink holes. During buried piping inspections, the extent of piping to be inspected will be sufficient to be representative of that portion of buried piping.*

Locations for focused inspections will give consideration to applicable attributes such as operating experience and areas of highest likelihood of corrosion problems. Degradation noted will be evaluated through the Corrective Action Program, including identification of additional locations for further inspections. Based upon the above techniques and the good operating experience of buried piping at CR-3, implementation of the Buried Piping and Tanks Inspection Program provides reasonable assurance that the aging effect of loss of material due to corrosion mechanisms will be managed such that systems and components within the scope of License Renewal will continue to perform their intended functions consistent with the CLB for the period of extended operation.

RAI B.2.21-1

Background:

In the CR3 LRA Section B.2.21, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping," the applicant states that the program is consistent with the program elements in GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small Bore Piping," including program Element 5, "Monitoring and Trending."

Issue:

During an onsite audit review, the staff noted that the applicant does not have specific information regarding the subject small bore piping weld population, and inspection sampling location and size. This information is needed to evaluate consistency with the GALL Report program element.

Request:

Provide quantitative description of the weld population, including total number of Class 1 small bore welds less than 4 inch NPS, the number of socket welds, and the number of welds two inch or less. Describe your methodology considered in determining the one-time inspection sampling size and locations, and how the program addresses factors such as susceptibility, risk, and operating experience.

Response

The methodology to be employed is derived from "Elementary Statistical Analysis" by S.S. Wilks for sampling from a finite binomial population. This methodology was used as the basis for the sampling program description in EPRI Report TR-107514, "Age-Related Degradation Inspection Method and Demonstration: In Behalf of Calvert Cliffs Nuclear Power Plant License Renewal Application." The sample size is selected to provide a 90 percent confidence that 90 percent of the population will not display degradation (90/90). As stated in this report, one key conservative feature of applying the 90% confidence level is the assumption that none of the inspected items will contain significant aging effects. Consequently, if a single item in the sample population has an aging effect of interest, the sample size is increased which will raise *the confidence level to greater than 90%. The locations selected for inspection are taken from the population of welds that have been selected for risk-informed inspection. Therefore, the confidence level is greater than 90% since the inspection locations selected are the most susceptible to aging effects.*

There are a total of 539 Class 1 piping welds regardless of size or type. Assuming that all the Class 1 welds are small bore would yield a population size of 24. CR-3 will perform a volumetric examination of 24 small bore piping butt welds within the last ten years of the original license period.

The program description in the LRA will be revised to state:

> *The volumetric inspections will be completed prior to the end of, and within the last ten years of, the current operating period.*

Commitment #16 will be revised to state:

> *The One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program is a new program to be implemented. CR-3 will perform a volumetric examination of 24 small bore piping butt welds within the last ten years of the original license period.*

With a combination of proven statistical sampling, focus on susceptible locations, and a mechanism for increasing the sample size, the One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program provides assurance that the applicable components will continue to perform their intended function through the period of extended operation.

This response involves changes to the LRA as shown in Enclosure 2 and a change to License Renewal Commitment #16 as shown on Enclosure 3.

RAI B.2.21-2

Background:

In the CR-3 LRA Section B.2.21, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping," the applicant stated that the program is consistent with the program elements in GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small Bore Piping," which recommends one-time volumetric inspection of small bore piping.

Issue:

The CR-3 application stated that its small bore socket welds will be excluded from the volumetric examination. No additional information was provided regarding its technical basis.

Request:

Please explain how the aging effects of SCC and fatigue in socket welds are addressed. Provide your supporting program information and technical basis.

Response

A telephone conference was held between the NRC and the NEI Task Force and included a discussion related to this issue (See the 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, dated March 6, 2007 (ADAMS Accession Number ML070580498)). The summary states:

> *An issue was raised during a recent safety audit at a plant applying for license renewal. The issue was whether or not socket welds should be included in the "One-Time Inspection of Small Bore Piping," GALL AMP XI.M35. The current GALL AMP for small bore piping does not mention socket welds. American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME) Section XI, IWB-2500, Category B-J requires a surface examination for socket welds larger than 1 inch nominal pipe size. The industry met with the staff on August 20, 2000, and proposed a substitution of VT-2 in place of surface or volumetric examinations of socket welds. ASME Code Case N-578-1 permits VT-2 examination of socket welds each refueling outage. The plant referred to with [sic] the recent safety audit has not had a history of failures of small bore piping including socket welds. Industry experience has shown that failures of socket welds are generally internally initiated, and surface examinations are not effective in detecting cracks until they are through wall. As a result of internal discussions with the staff, the staff concluded that no additional examinations will be required for socket welds in addition to the current ASME code requirements for license renewal.*

The program description in the CR-3 LRA states:

> *In addition, the Program will include controls to ensure that ASME Class 1 socket welds are inspected in accordance with the approved ASME Section XI ISI program.*

As indicated in LRA Tables 3.1.2-1 and 3.1.2-3, the aging management of small-bore lines is consistent with NUREG-1801, Volume 2, Item IV.C2-1 that requires a combination of ASME Section XI Inservice Inspection, Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-Bore Piping.

Socket welds will receive risk-informed examinations (RISI). Socket welds, selected for examination under the RISI program, are to be inspected with a VT-2 visual examination each refueling outage per ASME Code Case N-578-1 (see footnote 12 in Table 1 of the Code Case). To facilitate this, socket welds selected for inspection under the RISI program shall be pressurized each refueling outage in accordance with Paragraph IWA-5211(a).

This position is aligned with recent Safety Evaluation Reports and was proffered to the ACRS by the NRC staff.

Therefore, the aging management strategy employed for small-bore Class 1 socket welds is in alignment with current industry practices and previously articulated positions of the NRC staff.

RAI B.2.22-1

Background:

The GALL Report states that AMP XI.M36, "External Surfaces Monitoring," manages aging of "steel" components (defined in the GALL Report as carbon steel, alloy steel, etc., and "does not include stainless steel") for loss of material, through visual examinations to identify indications of:

- corrosion and material wastage (loss of material)
- leakage from or onto external surfaces
- worn, flaking, or oxide-coated surfaces
- corrosion stains on thermal insulation
- protective coating degradation (cracking and flaking)

The scope of this AMP indicates that it is intended to identify visible rust or rust byproducts (e.g., discoloration or coating degradation) such that loss of material caused by corrosion can be detectable prior to any loss of intended function. This AMP does not identify other aging effects beyond loss of material.

CR-3 LRA Section B.2.22 identifies the plant's External Surfaces Monitoring Program as an existing program that, following an enhancement, will be consistent with the GALL Report. The supporting calculation, L08-0635, states that procedures will be enhanced to assure proper monitoring. L08-0635 states that the program will monitor "loss of material, hardening and loss of strength of elastomers, and reduction of heat transfer caused by fouling." The LRA states that for elastomers, "...the program will include inspection attributes for aging effects that could reasonably be detected through visual inspection. Attributes that require physical manipulation are not included in the program."

Issue:

The intent of GALL AMP XI.M36 is to monitor the aging effects of carbon steel and ferrous materials through visual inspections to identify corrosion, corrosion products, and coating degradation. The program is not intended to monitor reduction of heat transfer, hardening or loss of strength. These parameters cannot be tracked visually. For the "range of [additional] materials," scoped in this program by the applicant, (stainless steel aluminum, copper, elastomers, PVC, thermoplastics, fiber glass, and fiber reinforced plastics) aging effects cannot be determined visually. The additionally scoped materials may render the External Surfaces Monitoring Program as implemented, not consistent with the GALL Report. Traditionally, the staff has considered the inclusion of these additional materials an exception to the GALL AMP.

Request:

1. Justify why the added range of materials is not an exception to GALL. Provide the basis for:

    a. Concluding that your External Surfaces Monitoring Program requires "enhancement" to be consistent with the GALL AMP, when your enhancements are beyond the scope of the GALL AMP.

   b. Including in your "consistent with GALL" program items not subject to loss of material by corrosion when the GALL AMP specifies detection of visible rust and rust byproducts (or visible coating degradation).

2. What inspection attributes will be implemented (e.g., parameter monitored/inspected, acceptance criteria, etc.), so that all SSCs identified in your LRA as covered by this AMP will be effectively monitored and managed for the aging effects cited?

3. As described in the scope for the program, describe how monitoring of degradation of paint and coatings will be performed.

4. For elastomers, identify the methods and procedures that will be used to identify loss of strength or hardening without physical manipulation of the elastomer.

5. For the following non-metallic materials identify methods or procedures to track wastage, loss of strength, and loss of material:

   a. PVC
   b. Thermoplastics
   c. Fiber Glass
   d. Fiber Reinforced Plastics

6. For the following metallic materials identify methods or procedures to track corrosion, oxidation, rust, and any other relevant aging effect:

   a. Copper
   b. Stainless Steel
   c. Aluminum
   d. How will reduction of heat transfer be monitored using this AMP?

<u>Response</u>

The External Surfaces Monitoring Program has been revised to consider additional materials and aging effects not in the scope of the GALL Program description to be an exception to GALL. The program utilizes inspection attributes that can be implemented during visual examinations of the specified materials for the aging effects it manages. This program does not incorporate physical manipulation of elastomers for hardness, loss of strength, or other volumetric properties. Physical manipulation/testing of elastomeric components is accomplished within aging management activities specified for internal surfaces by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.

The program includes visual examinations to detect degradation of paint and protective coatings. Examination procedures will include inspection attributes relevant to the detection of aging of paint and protective coatings such as cracking, flaking, blistering, and missing coating.

The program includes visual examinations to detect age related degradation of polymers and elastomers. Examination procedures will include inspection attributes relevant to degradation of polymers and elastomers, such as cracking, peeling, blistering, chalking, crazing, delamination, flaking, discoloration, physical distortion, gross softening, indications of wear, and loss of material.

CR-3 evaluated aging effects to be potentially applicable for external surfaces of copper, aluminum, and stainless steel, even though NUREG-1801 predicts no aging effects for these corrosion resistant materials in an indoor-air environment. The program is credited with aging management of these materials for loss of material due to corrosion, consistent with the treatment of carbon steel. Examination procedures will include inspection attributes relevant to corrosion of metals, such as visual detection of loss of material, and evidence of corrosion mechanisms, such as rust/oxidation, sensitization, and discoloration.

The External Surfaces Monitoring Program is credited with managing Reduction of Heat Transfer Effectiveness due to Fouling of Heat Transfer Surfaces for radiator tubes on the Appendix R Chiller. These finned tubes are located outside, and are externally visible for examination of fins and heat transfer surfaces for evidence of fouling that would result in a reduction of heat transfer.

The External Surfaces Monitoring Program is implemented through regularly performed, procedurally directed walkdowns and inspections. Inspection attributes and acceptance criteria are provided in the governing procedures, and unacceptable conditions are resolved through the Corrective Action Program, including ongoing monitoring/trending, as appropriate.

This response involves a change to the LRA, as discussed in Enclosure 2, and to License Renewal Commitment #17 as indicated in Enclosure 3.

RAI B.2.25-1

Background:

GALL AMP XI.S1, "ASME SECTION XI, Subsection IWE," recommends implementation of the ISI requirements of Subsection IWE, in accordance with 10 CFR 50.55a, and considers this a necessary element of aging management for concrete containments through the period of extended operation. This includes liner plate corrosion concerns described in the NRC generic communications.

Issue:

Page 43 of the CR-3 calculation L08-0616, "Description of the ASME Section XI, Subsection IWE Program," describes deterioration of the moisture barrier at reactor building 95 foot elevation. Liner plate thickness at this elevation was measured in 1997. Thickness of the liner in one area at the interface liner and at the moisture barrier location was measured by ultrasonic methods. The measured thickness was 0.307 inch as compared to nominal measured thickness of 0.390 inch (21% reduction in thickness).

Request:

Has the degraded area that was subjected to accelerated corrosion been UT examined in the successive outages since 1997 as recommended in IWE-1241 and Table IWE-2500-1 for augmented inspection? This information is required to determine if the effects of aging of the liner plate can be adequately managed during the period of extended operation as required by 10 CFR 54.21(c)(3).

Response

The degraded area at the liner to moisture barrier interface that was UT examined in 1997 was not designated as a Surface Area Requiring Augmented Examination in accordance with IWE-1241. There have been no additional inspections of the degraded area since 1997. At the time of discovery, CR-3 had not yet developed an IWE/IWL Inspection Program. The amended rule of 10CFR50.55a (effective September 9, 1996) gave utilities until September 09, 2001 to complete the 1st Period examinations required by ASME Section XI IWE and IWL. CR-3 did not develop the IWE/IWL Program and submit requests for code relief to the NRC until November 30, 1998. The 1st Period examinations were begun during Refueling Outage (RFO)-11 between October - November 1999. The results of these initial examinations were submitted in the RFO-11 90-day Inservice inspection (ISI) Summary Report to the NRC on February 9, 2000.

Since the Program inception, CR-3 has inspected the moisture barrier and liner every period as required by ASME Section XI, Subsection IWE with no items of discovery that were classified as a Surface Area Requiring Augmented Examination under IWE-1241. The entire circumference of the Reactor Building was visually examined in 1997. The liner plate results were evaluated by Engineering. The examinations included thickness measurements to determine actual wastage. One area had a measured pit depth of 0.065 inch with a remaining wall thickness of 0.307 in. at an area of the liner with a UT thickness reading of 0.372 in. The nominal design thickness is 0.375 in. and the minimum design thickness is 0.312 in. Engineering determined that the reduction in cross sectional area of the liner was negligible with respect to the calculated stress and the ultimate stress and the overall stress level in the liner plate was insignificant. This was the only area which was less than minimum design thickness. The degraded area was prepared for recoating, then recoated; and the moisture barrier was installed at the liner plate concrete interface per the design.

RAI B.2.25-2

Background:

GALL AMP XI.S1, "ASME SECTION XI, Subsection IWE," recommends inspection of the containment liner plate in accordance with ASME Subsection IWE, Subarticle IWE-2411 and Table IWE-2411-1.

Issue:

According to Page 43 of the CR-3 calculation L08-0616, "Description of the ASME Section XI," the moisture barrier at containment base slab was reinstalled in 1997. However, the moisture barrier separation from liner plate and degradation was again documented starting in 2003. In 2007, the moisture barrier was found to be damaged at 12 locations with lengths of up to 36 inches. The damaged moisture barrier provides a path for water penetration at and below the floor level, and can affect the leak tightness of the containment during the period of extended operation.

Request:

Discuss any additional investigation and testing that are planned in addition to the visual examination of the moisture barrier during the 2009 refueling outage to determine the extent of liner plate corrosion at the moisture barrier and wall and floor liner plate below the moisture barrier. This information is required to determine if the effects of aging of the liner plate can be adequately managed during the period of extended operation as required by 10 CFR 54.21 (c)(3).

Response

CR-3 has planned for a full visual examination of the accessible IWE components including the accessible liner wall and all moisture barrier in the 2009 refueling outage (RFO16). In addition, CR-3 will be performing repairs of the degraded moisture barrier as needed to ensure a watertight seal between the concrete and the liner plate. Any areas of corrosion of the liner plate which are unsatisfactory will be further evaluated as to the extent of the degradation and any addition corrective actions to be performed. There are no plans to remove the moisture barrier to investigate the condition of the liner plate at the interface point of the liner and the moisture barrier or to remove concrete to inspect the floor liner plate during the 2009 refueling outage.

RAI B.2.25-3

Background:

GALL AMP XI.SI, "ASME Section XI, Subsection IWE," recommends inspection of the containment liner plate in accordance with ASME Subsection IWE, Subarticle IWE-2411 and Table IWE-2411-1.

Issue:

Action request AR 00257242 identified bulging in the liner plate at numerous locations. Additional investigation indicated hollow sounds at the bulge locations. This indicates separation of the liner plate from the containment concrete. In addition, AR 00257242 documented numerous failures in the coating for the liner plate.

Request:

1. Has any testing been performed to determine the gap between the liner plate and concrete? Provide details of any analysis performed to determine whether the separation of the liner is acceptable during all design basis loading conditions during the period of extended operation.

2. Is there a separate aging management program to monitor the containment liner plate coating degradation during the period of extended operation? If not what is the basis for evaluating the damage to the coating.

Response

1. *There has been no testing to determine the gaps between the liner plate and concrete. Bulges or indications of bulges determined through tapping are identified on inspection data sheets. These coated areas were visually inspected for corrosion and*

representative UT performed to determine if the liner plate thickness met the minimum design thickness.

During the refueling outage in 2007, 28 bulges in the liner plate at various locations were identified during the general visual examination. Two of the bulged areas were 12 in. x 36 in., one was 12 in. x 24 in. and the remainders were all 12 in. x 12 in. Each of these locations had a detailed visual examination performed. The coating was satisfactory, and there was no rust or deterioration of the bulged liner plate identified. Three of the areas were selected for further evaluation for determination of thickness by UT. Average thickness reading for the four quadrants of each bulged area ranged between 0.358 in. and 0.371 in. which is well above the minimum design thickness of 0.312 in. Since the areas that were tested were representative of all the bulged areas and met all requirements, no further UT was performed. It was determined that the areas were minor in nature and did not adversely affect the structural integrity of the Reactor Building or its capability to perform its intended function over the next refueling cycle. These areas will continue to be visually inspected in accordance with ASME Section XI, Subsection IWE requirements.

2. *The Containment liner plate is monitored for corrosion or degraded protective coatings by the ASME Section XI, Subsection IWE Program as stated in LRA Section 3.5.2.2.1.4. In addition, LRA Section 2.1.3, Generic Safety Issues, discussed GSI-191, Assessment of Debris Accumulation on PWR Sump Performance, and stated that CR-3 does not credit coatings to assure that the intended functions of coated structures and components are maintained. The basis for inspecting damage to the coating is that CR-3 meets the requirements of ASME Section XI, Subsection IWE, paragraph 2310, which states "Painted or coated areas shall be examined for evidence of flaking, blistering, peeling, discoloration, and other signs of distress." CR-3 also meets the acceptance standards of ASME Section XI, Subsection IWE 3510.2, Visual Examination of Coated and Noncoated Areas. The implementing documents for the ASME Section XI, Subsection IWE Program at CR-3 have incorporated the Code requirement for inspecting and evaluating the coating damage which will continue through the period of extended operation. Further information is included in the response to RAI XI.S8 provided in Progress Energy letter to the NRC 3F1009-06.*

RAI B.2.26-1

Background:
GALL AMP XI.S2, "ASME Section XI, Subsection IWL," states that NRC IN 99-10 described occurrences of degradation in prestressing systems, and recommends that the applicant to consider the degradation in prestressing systems.

Issue:

The Operating experience section of LRA Section B.2.26 states that IN 99-10 was reviewed for applicability to CR-3. It was determined that the procedure used to control the tendon surveillance addressed the issues in the IN 99-10. The data for the CR-3 tendon history was reviewed using regression analysis, and the results did not vary appreciably from trending the group averages. However, LRA Section B.2.26 does not address the issue of high relaxation of prestressing steel wires at high operating temperature inside the containment. In addition, Calculation S07-033, Revision 0, Dated October 10, 2007, uses a loss in prestress due to relaxation to be only 2.95 percent at the end of 40 years. IN 99-10 reported a loss of prestress of 15.5 to 20 percent over a 40 year period at an average temperature of 90°F.

Request:

Explain how the loss of prestress of 2.95 percent due to relaxation of steel was determined and whether it is based on any test data.

Provide details of the informal review performed which determined that trending analysis for group averages is an acceptable method instead of the individual tendon lift-off forces linear regression analysis as recommended in IN 99-10.

Response

The original wire relaxation curve, provided by test data from the wire vendor, forms the bases for the wire relaxation value. The original wire relaxation curve was based on the wire described in the FSAR Section 5.2.2.3 and the relaxation curve shown on FSAR Figure 5-26. A calculation made conservative adjustments to the original stress relaxation value shown in FSAR Figure 5-26. The values on FSAR Figure 5-26 for wire number 6 were multiplied by a factor of 2.68 to obtain the relaxation loss in percent at specific years. The 2.68 multiplication factor was from two factors. A 1.47 factor was determined to allow for a long term temperature of 104°F vs. 68°F on FSAR Figure 5-26. A 1.82 factor was determined based on a conservative relaxation value of 2% at 40 years, as opposed to a 1.1 per cent on FSAR Figure 5-26 (2.0/1.1) to address scatter in the test data. The final factor of 2.68 was determined by multiplying 1.47 x 1.82. The 2.95 per cent loss was determined by multiplying the 2.68 factor times the interpolated value of 1.1 at 40 years on FSAR Figure 5-26. It should be noted that wire relaxation was only one part of the individual losses which are input to the calculated total losses.

For the 30-year tendon surveillance performed in 2007, a comparison of the as-found lift-off forces to the original installation lock-off forces was made to determine if there was any evidence of system degradation. The losses since original installation for each tendon group were reported as 6.7% for the vertical tendons, 17.1% for the hoop tendons and 16.5% for the dome tendons. These losses coincided with what was expected and based on the data, and it was concluded the results do not indicate any degradation of the post tensioning system. These are in line with the IN 99-10 reported loss of prestress of 15.5% to 20% over a 40 year period.

Details of the informal review of CR-3 tendon history, which was referred to in the operating experience review of the License Renewal basis calculation, could not be located. The informal review had determined that trending analysis for group averages was an acceptable method instead of the individual tendon lift-off forces linear regression analysis as recommended in IN 99-10. The operating experience review discussed earlier methodology used at CR-3 which has been enhanced over time.

For the 30th year tendon surveillance performed in 2007, CR-3 used individual tendon lift-off force linear regression analysis. A regression analysis was conducted on each of the tendon groups. Regression analysis curves were plotted for each group with as-found lift-off values plotted for each tendon along with the age since the time the tendon was stressed. The *analysis determined that the vertical, hoop, and dome tendons will remain above the minimum force requirements well beyond the next surveillance - as well as beyond 60 years. The forecasted values at 60 years was +29.4% above minimum design for the vertical tendons, +5.8% for the hoop tendons, and + 9.9% for the dome tendons. Regression analysis curves were plotted for each group as part of the report.*

Based on the above, CR-3 meets the methodology described in IN 99-10. However, the operating experience discussion in LRA Subsection B.2.26 should be clarified to state that CR-3 methodology has been enhanced to use individual tendon lift-off force linear regression analysis as discussed in IN 99-10. Refer to the LRA changes described in Enclosure 2.

RAI B.2.26-2

Background:

GALL AMP XI.S2, "ASME Section XI, Subsection IWL" states that trending and monitoring of prestressing forces in tendons for prestressed containments be in accordance with 10 CFR 50.55a(b)(2)(viii). In addition, 10 CFR 55.55a and ASME Subsection IWL also require that prestressing forces in all inspection sample tendons be measured by lift-off tests and compared with acceptance standards based on predicted force.

Issue:

During the several prestressing tendon surveillance inspections over the last 20 years, the lift-off forces in the hoop prestressing tendons have been consistently found to be lower than the 95 percent of predicted values. After the last (eighth) tendon surveillance in 2007, NCR 251318 disposition require follow up action to investigate the basis for the acceptance curves for tendons and determine why this criteria is typically more stringent than the life of plant curves.

Request:

What is the status of the investigation for the discrepancy in the actual lift-off and predicted forces for the prestressing tendons since it may affect the structural integrity of CR-3 containment during the period of extended operation?

<u>Response</u>

NCR 251318 was closed on April 22, 2009 with no additional actions required. The Responsible Engineer stated in the closing the NCR that while several tendons have demonstrated lower than expected lift-off values, leading to adjacent tendons being tested, the end result in all cases thus far has met the acceptance criteria for any overall group. As such, there is currently no adverse condition. The criteria established as part of the design basis for the containment integrity system has been and continues to be met. Therefore, no further actions were required. Future tendon surveillances will continue to monitor the containment integrity system and any findings or actions required will be resolved. In addition, the tendon stress relaxation analysis included in LRA Section 4.5 included these lower than expected lift-off values and still showed the tendon prestresses will remain above the minimum required values for the period of extended operation.

RAI B.2.26-3

Background:

GALL AMP XI.S2, "ASME Section XI, Subsection IWL" references the American Concrete Institute (ACI) 201.1R-77 for identification of concrete degradation.

Issue:

Page 20-21, Section 6-3 of the CR-3 calculation L08-0617 states that ACI 201.1R-69 and R-92 were used in the development of the conditions indicative of degradation of IWL components, and use of the different editions of the ACI code is consistent with GALL.

Request:

Provide justification that use of ACI 201.1R-69 and R-92 editions are consistent with GALL without any exception.

Response

CR-3 did use ACI 201.1 R-69 and R-92 in the development of the conditions indicative of damage or degradation of IWL concrete surfaces. However, Section IWL-2510, Surface Examination, of ASME Section XI, Subsection IWL Code, 2001 Edition through the 2003 Addenda to which CR-3 is committed, specifies ACI 201.1 without the year 77 or 92 designated. Since NUREG-1801, Program XI.S2, ASME Section XI, Subsection IWL includes the 2001 Edition through the 2003 Addenda, and CR-3 is in compliance with this Code, CR-3 considers this consistent with NUREG-1801 Program XI.S2, not an exception.

RAI B.2.26-4

Background:

GALL report AMP X1.S2, "ASME Section XI, Subsection IWL" recommends that selected areas, such as those that indicate suspect conditions and areas surrounding tendon anchorages, receive a more rigorous VT-1 or VT-1C examination.

Issue:

It is not clear from Page 17-18 of the CR-3 calculation L08-0617 whether CR-3 inspects selected concrete surfaces that indicate suspect conditions and areas surrounding tendon anchorages by performing VT-1/ VT-1C examination or follow ASME Subsection IWL requirements.

Request:

Is the CR-3 inspection of selected areas of concrete that indicate suspect conditions and areas surrounding tendon anchorages consistent with GALL AMP X1.S2?

Response

CR-3 performs inspections of selected concrete surfaces that indicate suspect conditions and areas surrounding tendon anchorages by performing "detailed visuals" in accordance with ASME Section XI, Subsection IWL Sub-Articles IWL-2510, IWL-2524 and IWL-2310(b). This meets the requirements of ASME Section XI, Subsection IWL Code 2001 Edition through the 2003 Addenda to which CR-3 is committed. Since NUREG-1801, Program XI.S2, ASME Section XI, Subsection IWL includes use of the 2001 Edition through the 2003 Addenda, and CR-3 is in compliance with this Code, CR-3 considers this consistent with NUREG-1801 Program XI.S2, not an exception.

The NUREG-1801, Program XI.S2, ASME Section XI, Subsection IWL Evaluation and Technical basis statements for item 4, Detection of Aging Effects do not match the text in the ASME Section XI, Subsection IWL Code 2001 Edition through the 2003 Addenda. The ASME Section XI, Subsection IWL Code 2001 Edition through the 2003 Addenda refers to "detailed visual" which replaced the terms "VT-1" and "VT-1C" utilized in earlier editions of the Code.

RAI B.2.28-1

Background:

Page 21 of the Crystal River Aging Management Program for 10 CFR 50, Appendix J (Calculation L08-0615), states that a technical specification change may be generated to take credit for IWE and IWL examinations.

Issue:

Appendix J of 10 CFR 50 requires a general inspection of the external and exterior surfaces to be performed prior to Type A test.

Request:

Explain how IWE examination performed during a period of 10 years can be credited for general inspection required to be performed prior to Type A Test.

Response

CR-3 has chosen to use 10 CFR 50 Appendix J, Option B (Performance-Based Leakage-Test Requirements) for Type A testing. The 10 CFR 50 Appendix J, Type A Testing (ILRT) implementing procedure allows the containment general inspection requirements to be met by the visual examinations performed by ASME Section XI, Subsection IWE. The inspections performed by ASME Section XI, Subsection IWE using VT-3 and VT-1 qualified inspectors are considered equivalent or better than the general visual inspections performed by engineering personnel (which are required by 10CFR50.55a Appendix J). The examinations are performed prior to the ILRT, when the IWE examinations and the ILRT are performed during the same refueling outage. During outages when an ASME Section XI, Subsection IWE inspection is not performed, a separate visual examination may be performed by engineering and documented in accordance with the ILRT implementing procedure.

CR-3 implementation of 10 CFR 50, Appendix J meets the technical requirements of NEI 94-01, Revision 0. However, a later issuance of NEI 94-01, Revision 1, Section 9.2.1, "Pretest Inspection and Test Methodology" recommends that IWE examinations be credited for pretest inspection of Type A testing:

> *"It is recommended that these inspections [Type A pretest inspections] be performed in conjunction or coordinated with the ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWE/IWL required examinations."*

This indicates that ASME Section XI, Subsection IWE examinations performed during a period of 10 years are acceptable and recommended to meet 10 CFR 50, Appendix J requirements.

RAI B.2.28-2

Background:

Appendix J, 10 CFR 50 specify halide leak-detection method or rate of pressure loss method as acceptable methods for performing Type B and C tests.

Issue:

CR-3 Type B and C tests are performed using make-up-flow method. In addition pages 19, 35, and 37 of calculation L08-0615 states that make-up-flow method as the NRC preferred method.

Request:

Provide justification for using make-up-flow method and documentation that indicate that makeup-flow as the NRC preferred method. Use of an unqualified method for leakage testing may affect the leakage rate results which may be used to predict containment performance during period of extended operation.

<u>Response</u>

CR-3 has chosen to use 10 CFR 50 Appendix J, Option B - Performance-Based Leakage-Test Requirements for Type B and C testing. The halide leak-detection method or rate of pressure loss methods are specific to Option A - Prescriptive Requirements. Option B does not specify acceptable methods for Type B and C testing. Per 10 CFR 50 Appendix J, for Option B, Section V.B foot note (3) states: "Specific guidance concerning a performance-based leakage-test program, acceptable leakage-rate test methods, procedures, and analyses that may be used to implement these requirements and criteria are provided in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program." Regulatory Guide 1.163 in its Regulatory Position states NEI 94-01, "Industry Guideline for Implementing Performance-Based Option of 10 CFR Part 50, Appendix J" provides methods acceptable for complying with the Option B requirements. Regulatory Guide 1.163 also states the technical methods and techniques for performing Type A, B, and C tests contained in ANSI/ANS-56.8-1994, "Containment System Leakage Testing Requirements", are acceptable to the NRC staff. ANSI/ANS-56.8-1994 provides acceptable test methodologies and details for Appendix J Type B and C Testing. Two acceptable test methodologies for measuring leakage rates of primary *containment boundaries and isolation valves are provided: Make-up flow rate method and Pressure decay method. CR-3 selected the use of the Make-up flow rate method.*

Based on the discussion provided above, the Make-up flow rate method used at CR-3 meets 10 CFR 50 Appendix J, Option B requirements.

The statement in the 10 CFR 50 Appendix J Program License Renewal basis document that the "Make-up-flow method is the test preferred by the Nuclear Regulatory Commission" was a quote from an internal company response to an audit performed at CR-3 in 1995. The quote was documented in the Plant Operating Experience review portion of the License Renewal basis document and is a historical record. During the RAI review, no basis for this statement was discovered. It is believed the historical statement should have said the Make-up-flow method is the test preferred by CR-3 since the 10 CFR 50 Appendix J Program Manual states "This is the preferred leakage rate method to be used at CR-3."

The 10 CFR 50 Appendix J Program License Renewal basis document will be revised to remove the statement that the Make-up-flow method is the test preferred by the Nuclear Regulatory Commission.

RAI B.2.28-03

Background:

10 CFR 50, Appendix J requires periodic performance of Type A test for detecting degradation of containment boundary.

Issue:

The table on Pages 22 and 23 of the CR-3 10 CFR 50 Appendix J Program (calculation L08-0615) provides results of the Type A test (ILRT) tests over the life of the plant. According to this Table, the containment leakage rate during 2005 test was two times of that recorded during the previous test performed during 1991.

Request:

Has the root cause for the 100 percent increase in the leakage rate between two successive tests been determined since it can affect the structural integrity of the containment to resist the design basis accident pressure load during the period of extended operation?

Response

There was not a root cause performed for the As-Found 2005 Type A integrated leak rate test (ILRT) since all acceptance criteria was successfully met (0.19566 < 0.25 %wt/day). The test result for 2005 was more closely associated with earlier test results such as in 1983 (0.179) and 1987 (0.147) rather than 1991 (0.1105) and was not considered a trend affecting the structural integrity of the containment.

Additionally, test methodology may vary from test to test for ILRTs. In 1991, a Mass Point Analysis was used as the credited test method. In 2005 a Total-time Analysis was used as the credited test method. Either method is allowed per the ILRT plant procedure.

The measured leakage rate in 1991 was 0.0962 %wt/day and in 2005 was 0.0968 %wt/day, prior to applying penalties, corrections, and savings, which are very comparable values. The final As-Found ILRT leakage rates for 1991 and 2005 deviate due to the application of confidence intervals and leakage savings penalties. The application of a confidence interval is normally more taxing for a Total-time Analysis test (which was used in 2005) than that of a Mass Point Analysis (as used in 1991), due to the reduced duration of the test (a minimum of 6 hours vs. 8 hours), the higher confidence interval required (97.5% vs 95%), and the reduced number of data points collected during the test (a minimum of 20 vs. 30). The difference due to confidence interval application accounted for approximately 0.03 wt%/day increase in 2005 when compared to results in 1991 (this is essentially the difference between the As-Left ILRT results from 1991 to 2005). Furthermore, leakage savings, i.e., the difference between As-Found and As-Left Local Leak Rate Tests (LLRTs), accounted for a large portion of the differences in the 1991 and 2005 As-Found ILRT leakage calculations. Leakage savings in 2005 totaled 0.06046 %wt/day and only 0.00038 %wt/day in 1991, accounting for a 0.06008 %wt/day increase in total As-Found ILRT leakage results when comparing the 1991 and 2005 tests. These leakage savings were the result of maintenance performed on components that improved Type B and C As-Left LLRTs during the 2005 refueling outage. Leakage savings is defined as the difference between the As-Found and As-Left Type B and C LLRTs and is factored into the ILRT results to obtain an As-Found value for overall containment leakage. Thus, the increase in As-Found ILRT results from 1991 to 2005 are explained by differences in test methodology (Total-time Analysis vs Mass Point Analysis) and the results of individual component (Type B and C) LLRT improvements made by performing maintenance.

RAI B.2.30-1

Background:

According to operating experience described in the LRA Section B.2.30 the Structures Monitoring Program is an existing program and currently the frequency of inspection is 10 years.

Issue:

The LRA states that the Structures Monitoring Program is consistent with GALL AMP XI.S6. Also, the program basis document states that the inspection criteria provided within the structures monitoring program are primarily taken from ACI 349.3R-96 which is inconsistent with the GALL Report recommendation. Ten years inspection frequency for all structures and components is not in conformance with ACI 349.3R-96. ACI 349.3R-96, Chapter 6 recommends that the selected inspection frequency should provide assurance that any age-related degradation is detected at an early stage and that appropriate mitigative actions can be implemented. In addition, ACI 349.3R-96 also specifies a five-year (two per ISI interval) inspection for structures exposed to natural environment structures inside primary containment, continuous fluid exposed structures, and structures retaining fluid and pressure.

Request:

Provide justification for the inspection interval of 10 years and deviating from the ACI 349.3R-96 recommendations.

Response

CR-3 believes the Structures Monitoring program meets the guidance ACI 349.3R-96 and is consistent with GALL AMP XI.S6 based on the following justification.

GALL AMP XI.S6 Program Description states:

> *Implementation of structures monitoring under 10 CFR 50.65 (the Maintenance Rule) is addressed in Nuclear Regulatory Commission (NRC) Regulatory Guide (RG) 1.160, Rev. 2, and NUMARC 93-01, Rev. 2. These two documents provide guidance for development of licensee specific programs to monitor the condition of structures and structural components within the scope of the Maintenance Rule, such that there is no loss of structure or structural component intended function.*
>
> *Because structures monitoring programs are licensee-specific, the Evaluation and Technical Basis for this aging management program (AMP) is based on the implementation guidance provided in Regulatory Guide 1.160, Rev. 2, and NUMARC 93-01, Rev. 2. Existing licensee specific programs developed for the implementation of structures monitoring under 10 CFR 50.65 are acceptable for license renewal provided these programs satisfy the 10 attributes described below.*

The Structures Monitoring Program at CR-3 adheres to a corporate procedure which meets the requirements of RG 1.160, Regulatory Position 1.5, and NUMARC 93-01. The purpose of the corporate procedure is to provide direction for monitoring the structures in the scope of 10 CFR 50.65.

Of the ten attributes, those that relate to frequency of inspections are attributes 4 and 5. A discussion is provided for attributes 4 and 5.

Attribute 4 of the GALL AMP XI.S6 Program addresses the inspection schedule and states:

> *Detection of Aging Effects: For each structure/aging effect combination, the inspection methods, inspection schedule, and inspector qualifications are selected to ensure that aging degradation will be detected and quantified before there is loss of intended functions. Inspection methods, inspection schedule, and inspector qualifications are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 and ANSI/ASCE 11-90 provide an acceptable basis for addressing detection of aging effects. The plant-specific structures monitoring program is to contain sufficient detail on detection to conclude that this program attribute is satisfied.*

The inspection schedule is to ensure that aging degradation will be detected … before there is loss of intended function. This attribute states use of ACI 349.3R-96 is not required but the program is to contain sufficient detail on detection to conclude that this program attribute is satisfied. The corporate procedure provides sufficient detail to ensure that aging degradation *will be detected before there is loss of intended function. As discussed below, the inspection frequency is adjusted, if required, to ensure aging degradation will be detected before there is loss of intended function based on the condition of the structure.*

Attribute 5 of GALL AMP XI.S6 Program states:

> *Monitoring and Trending: Regulatory Position 1.5, "Monitoring of Structures," in RG 1.160, Rev. 2, provides an acceptable basis for meeting the attribute. A structure is monitored in accordance with 10 CFR 50.65 (a)(2) provided there is no significant degradation of the structure. A structure is monitored in accordance with 10 CFR 50.65 (a)(1) if the extent of degradation is such that the structure may not meet its design basis or, if allowed to continue uncorrected until the next normally scheduled assessment, may not meet its design basis.*

The corporate procedure meets the requirements of RG 1.160, Regulatory Position 1.5, which is an acceptable basis for meeting attribute 5. There is not a reference to ACI 349.3R-96 for Monitoring and Trending in attribute 5.

RG 1.160, Regulatory Position 1.5, states:

> *An acceptable structural monitoring program for the purposes of the maintenance rule should have the following attributes.*

Further, it also states, as one of these attributes:

- *The condition of all structures within the scope of the rule would be assessed periodically. The appropriate frequency of the assessments would be commensurate with the safety significance of the structure and its condition.*

The corporate procedure meets the intent of RG 1.160, Regulatory Position 1.5, in that it states:

> *The inspection interval shall be commensurate with the safety significance of the structure and its condition but shall not exceed ten (10) years.*

The guidance of ACI 349.3R-96 was used in the development of the corporate procedure in addition to RG 1.160, Regulatory Position 1.5, and NUMARC 93-01. A discussion on the use of ACI 349.3R-96 is provided as follows.

ACI 349.3R-96 Chapter 6 states, "The frequency at which periodic evaluations are conducted within the evaluation procedure should be defined by the plant owner," and "Frequencies should be based on the aggressiveness of environmental conditions and physical conditions of the plant structures," and "In general, it is recommended that all safety-related structures be visually inspected at intervals not to exceed 10 years. ACI 349.3R-96 Chapter 6 also states, "In addition, the frequency of inspection for other components should follow those in the table below." The table lists Structures exposed to natural environment, Structures inside primary containment, Continuous fluid-exposed structures and Structures retaining fluid and pressure with a 5 years inspection frequency.

The corporate procedure uses the general guidance of ACI 349.3R-96 Chapter 6 but does not implement specific frequencies of five years. However, the structure inspection frequency *methodology in the corporate procedure is described as follows for structures monitored by the corporate procedure. The corporate procedure requires performance of a baseline inspection of structures. The baseline structure inspection determines the inspection frequency commensurate with the safety significance of the structure and its condition but not exceeding ten years. After each periodic inspection of a structure, a reassessment of the inspection frequency is required to be performed based on the results of the inspection. Again, the inspection frequency is determined commensurate with the safety significance of the structure and its condition but not exceeding ten years. Specifics of how this methodology as been employed at CR-3 is described below.*

Baseline structural inspections at CR-3 were completed in 1997. The inspections performed did not identify significant degradation which required a more frequent inspection. Therefore the inspection frequencies were set at ten years for 2007. Prior to the periodic inspections in 2007, portions of two structures had the inspection frequencies changed due to observations made during plant walkdowns. A specific inspection of a concrete wall of the Spent Fuel pool inside the Auxiliary Building was added with a one year frequency to monitor any concrete crack growth. A specific inspection of the walls of the Decay Heat Vaults in the Auxiliary Building was added on a one year frequency to monitor for water intrusion/seepage and aging effects on the structure. Just prior to the inspections in 2007, the inspection frequency for interior of the Reactor Building (non IWE/IWL components) was changed to every three refueling outages due to the safety significance of the structure. After the 2007 periodic inspections, a decision was made by engineering to increase the inspection frequency of the East Cable Bridge to one year due to condition of the structure. The condition of the remainder of structures was satisfactory and did not require increased inspection frequencies. CR-3 has also committed to a five year frequency for the Water Control Structures in LRA Appendix B.2.30 for the period of extended operation.

In summary, CR-3 has implemented a Structures Monitoring Program which meets the requirements of RG 1.160, Regulatory Position 1.5, and NUMARC 93-01, and that following enhancement will be consistent with GALL AMP XI.S6. GALL AMP XI.S6 does not require compliance with the specific inspection frequencies in the ACI 349.3R-96 Chapter 6 although it is an acceptable basis. CR-3 employs the general guidance of ACI 349.3R-96 Chapter 6 although the Table inspection frequencies are not strictly used. The CR-3 Structures Monitoring Program uses a methodology for determining the frequency of inspection commensurate with the safety significance of the structure and its condition but not exceeding ten years. CR-3 has increased the frequency of inspections for several structures based on the safety significance of the structure and its condition as described in the examples for the Spent Fuel Pool wall, Decay Heat Vaults, the interior of the Reactor Building, and the East Cable Bridge.

RAI B.2.30-2

Background:

LRA Section B.2.30 "Structures Monitoring Program" is an existing program that monitors aging of plant structures, including water controlled structures. This program corresponds to NUREG-1801, XI.S6, "Structures Monitoring Program," and XI.S7, "Water Controlled Structures." LRA and onsite basis document credits the applicant's Structures Monitoring Program for "Inspection of Water-Control Structures Associated with Nuclear Power Plants." The GALL Report allows this; however, the GALL Report requires that the details pertaining to water-control structures included in AMP B.2.30 are to incorporate the attributes described in GALL AMP XI.S7.

Issue:

A review of LRA Section B.2.30 indicates that the applicant has compared the attributes in this program to GALL AMP XI.S6 only. LRA B.2.30 does not include any comparison with the attributes of the program for water controlled structures (GALL AMP XI.S7) to establish consistency with the GALL Report.

Request:

Provide a comparison of attributes of LRA B2.30 to GALL AMP XI.S7 so as to determine if the B.2.30 program is consistent with GALL AMPs XI.S6 and XI.S7.

Response

A comparison of the attributes of LRA B.2.30 (GALL AMP XI.S6, Structures Monitoring Program) to GALL AMP SI.S7 was completed and included with the basis document for LRA B.2.30. The results of the comparison are provided by each program Element from XI.S7:

Scope of Program

The Structures Monitoring Program includes the Intake Canal, Circulating Water Discharge Structure (Includes the Nuclear Services Sea Water Discharge Structure), Circulating Water Intake Structure, and the Raw Water Pits (Auxiliary Building) in the scope of the program. The Structures Monitoring Program, with enhancements provided in the LRA, is consistent with this program element of GALL XI.S7 with no exceptions.

Preventive Actions

No actions are taken as part of the Structures Monitoring Program or GALL AMP XI.S7 to prevent or mitigate aging degradation. The Structures Monitoring Program is consistent with this program element of GALL XI.S7 with no exceptions.

Parameters Monitored/Inspected

The Structures Monitoring Program identifies the monitoring and inspection parameters for water-control structures which include cracking, spalling, scaling, erosion, drainage, settlement, seepage, and gaps for concrete structures. For the Intake Canal (the only earthen water control structure), loss of material and loss of form are inspected as aging effects due to erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage as the aging mechanisms which are monitored. Enhancements to Structures Monitoring Program for the GALL XI.S7 AMP elements were included in the LRA. The Structures Monitoring Program corporate procedure meets the inspection guidance of Regulatory Guide 1.127 including settlement, slope stability, seepage, drainage systems, and slope protection. In addition, the Structures Monitoring Program uses periodic surveys of the Intake Canal to ensure sufficient canal depth exists to assure adequate cooling water to the plant. The Structures Monitoring Program, with enhancements provided in the LRA, is consistent with this program element of GALL XI.S7 with no exceptions.

Detection of Aging Effects

The Structures Monitoring Program uses visual inspections to primarily detect degradation of water-control structures on a frequency at least every 5 years. An enhancement to of the Structures Monitoring Program for the GALL XI.S7 AMP element 1-1 was included in the LRA. The Structures Monitoring Program, with enhancement provided in the LRA, is consistent with this program element of GALL XI.S7 with no exceptions.

Monitoring and Trending

The Structures Monitoring Program is an inspection and monitoring program as discussed in Parameters Monitored/Inspected. This program element for monitoring operations and maintenance procedures is associated with reservoirs and dams upon review of RG 1.127 paragraph C.2g. There are no operations or maintenance procedures associated with the Structures Monitoring Program. In general, self-assessments by the line and the oversight department ensure the effectiveness of plant processes as described in the FSAR section 1.7.1. The Structures Monitoring Program is consistent with this program element of GALL XI.S7 with no exceptions.

Acceptance Criteria

Specific acceptance criteria are provided for concrete inspections based on the guidance of Chapter 5 of ACI 349.3R-96 in the program implementing procedures. Specific acceptance criteria are provided for the Intake Canal in program implementing procedures based on the guidelines of Appendix II of the "Recommended Guidelines for Safety Inspection of Dams by the U.S. Army Corps of Engineers." Existing enhancements for the Structures Monitoring Program include those needed for the GALL XI.S7 AMP. The Structures Monitoring Program, with enhancement, is consistent with this program element of GALL XI.S7 with no exceptions.

Corrective Actions

The program implementing procedure provides directions on initiating Nuclear Condition Reports when the inspections discover unacceptable conditions. Corrective actions will be implemented through the CR-3 Corrective Action Program when inspection results do not meet the acceptance criteria. This program element is addressed in LRA Subsection B.1.3. The Structures Monitoring Program is consistent with this program element of GALL XI.S7 with no exceptions.

Confirmation Process

This program element is addressed in LRA Subsection B.1.3. The Structures Monitoring Program is consistent with this program element of GALL XI.S7 with no exceptions.

Administrative Controls

This program element is addressed in Subsection LRA B.1.3. The Structures Monitoring Program is consistent with this program element of GALL XI.S7 with no exceptions.

<u>Operating Experience</u>

NUREG-1801 is based on industry OE through January 2005. GALL and recent industry OE have been reviewed for applicability to CR-3. More recent OE is captured through the Operating Experience Program where it is screened for applicability. Examples of the types of deficiencies and corrective actions have been included in LRA B.2.30. No loss of intended functions for the water-control structures was identified. As stated in GALL XI.S7, it can be concluded that the inspections implemented in accordance with the guidance in the SMP for the water-control structures have been successful in detecting significant degradation before loss of intended function occurs. This process will continue through the period of extended operation. The Structures Monitoring Program is consistent with this program element of GALL XI.S7 with no exceptions.

RAI B.2.30-3

Background:

The LRA Section B.2.30 states that the Structures Monitoring Program will be enhanced to monitor ground water chemistry including consideration for potential seasonal variation.

Issue:

The LRA has an enhancement for the periodic groundwater chemistry monitoring including the seasonal variation. However, the frequency of the groundwater chemistry monitoring is not specifically stated.

Request:

1. Describe past and present groundwater monitoring activities at CR-3.
2. What is the current ground water monitoring frequency and what will be the frequency of groundwater monitoring under the extended period of operation?
3. Provide the location(s) where test samples were/are taken relative to the safety-related and important-to-safety embedded concrete foundations.
4. Indicate seasonal variations.
5. Explain the technical basis and acceptance criteria.

<u>Response</u>

1. *Historical groundwater monitoring has been associated with the Radiological Environmental Monitoring Program (REMP) as part of the Offsite Dose Calculation Manual (ODCM) at CR-3 since pre-startup. Groundwater flow, well locations, and general information are discussed in the FSAR Sections 2.4.1, 2.5.1, and 2.5.3. FSAR Section 2.5.3 reports the groundwater chemistry as more than 350 ppm chlorides with a pH of 7.0 to 7.1. A groundwater flow study was performed in 1995 which recorded similar results as recorded in the FSAR. In 2006, 10 new shallow wells and 3 new deep*

wells near the plant were installed as a result of NEI Groundwater Protection Initiative Guideline 07-07. In 2007, another Groundwater Flow Study was completed with similar results using the new wells. A figure in the ODCM shows the locations of the wells. For License Renewal, CR-3 performed groundwater chemistry testing from two of the ten shallow wells in 2007. The results of the chemical analysis were included in LRA Table 3.0-1 and showed the groundwater at CR-3 was non-aggressive.

2. *Groundwater monitoring associated with the REMP described in the ODCM is currently quarterly and monthly. Groundwater chemistry monitoring for the Structures Monitoring Program has not been implemented. A chemistry activity is to be established to sample and analyze the groundwater at two of the new wells starting in 2011, again in 2015 prior to the period of extended operation, and yearly starting in 2017 for the period of extended period of operation. The 1 year frequency will continue in the extended period of operation.*

3. *The 10 shallow wells are located below the berm and surround CR-3. The wells vary from about 150 ft. to 525 ft. from the safety-related structures located on the berm. There are three wells east of the berm, two south of the berm, four west of the berm, and one north of the berm. The two samples taken in 2007 for License Renewal were from wells east of the plant berm. These were selected because groundwater flows from east to west toward the plant berm. The future wells to be sampled will be selected from the 10 shallow wells.*

4. *The groundwater samples in 2007 were taken in March (Spring). Future samples will be taken varying between Spring, Summer, Fall and Winter. This will determine if there are changes in the groundwater chemistry due to seasonal changes in accordance with NUREG-1801.*

5. *The bases for the chemistry parameters for non-aggressive groundwater are provided in NUREG-1801 and NUREG-1557 as pH > 5.5, chlorides < 500 ppm, and sulfates < 1500 ppm. The chemistry results will be provided to CR-3 Engineering to trend the results. If individual readings or the trend indicate aggressive groundwater, corrective actions to investigate the result will be initiated.*

RAI B.2.30-4

Background:

During the LRA audit, a plant walkdown was performed. Various concrete degradation mechanisms were observed on the walls of the Tendon Access Gallery at the 75 foot elevation. The noted deficiencies/aging effects include cracking, leaching, blistering, and voids. Water on the floor at several places was also noted.

Issue:

Various aging effects were observed. The source of water is still unknown. According to the engineering inspection report in the program basis document, the condition is acceptable and no corrective action is required.

The applicant's structures monitoring program, AMP B.2.30, is an existing program which was developed for the implementation of structures monitoring under 10 CFR 5.65, and is consistent with GALL AMP XI.56. The same program will be used for the extended period of operation. To meet the GALL Report recommendations the program element "Acceptance Criteria" is selected to ensure that the need for corrective actions will be identified before loss of intended function.

Request:

Provide an explanation of how the effect of aging will be adequately managed so that the intended function of protecting the tendon anchorage hardware against corrosion will be maintained consistent with the current licensing basis (CLB) for the period of extended operation without taking any corrective action.

Response

The Tendon Access Gallery concrete and steel will be managed by the Structures Monitoring Program (SMP) during the period of extended operation. The most recent SMP visual inspection of the Tendon Access Gallery was performed April 24, 2007. For concrete, the inspection identified wet spots on the floor (ponding), white residue on the wall which was identified as evidence of leaching, and some minor cracking and degradation of concrete. The inspection also examined the exposed steel tendon caps and documented some of the paint was peeling. The inspection results were identified as not significant and did not warrant corrective actions based on meeting the acceptance criteria of the implementing procedure. In addition to the SMP, the ASME Section XI, Subsection IWL Program performs a visual examination of the concrete degradation around selected vertical tendon bearing plates and corrosion and cracking of the anchorage assemblies to meet program requirements. The most recent ASME Section XI, Subsection IWL Program visual examination performed in October – November 2007 determined that no abnormal Containment structure degradation has occurred. Areas inspected included the concrete around selected vertical tendon bearing plates and the anchorage assemblies in the Tendon Access Gallery. Acceptance criteria were met. The ASME Section XI, Subsection IWL Program will continue to manage aging effects for the concrete and steel associated with the tendons in the Tendon Access Gallery during the period of extended operation.

As stated in LRA Table 3.0-1, and discussed in the response to RAI B.2.30-3, groundwater at CR-3 was determined to be non aggressive. However, concrete cracking, loss of material, and change in material properties due to aggressive chemical attack and corrosion of embedded steel were selected as aging effects in the soil environment as discussed in LRA Section 3.5.2.2.2.2.4. CR-3 used high density, low permeability concrete mix designs as discussed in LRA Section 3.5.2.2.2.2.5, however, an increase in porosity and permeability (change in material properties) due to leaching of calcium hydroxide was selected as an aging effect requiring aging management because of leaching identified in the below-grade concrete in the Tendon Access Gallery.

The NRC audit walkdown performed on July 15, 2009 identified similar conditions as documented previously by the SMP inspection on April 24, 2007. Results were documented by CR-3 with additional walkdown results as follows:

There was about 1 inch of water in several areas on the floor on July 15, 2009 which was believed to be from the open hatch to the atmosphere and recent heavy rainfall and not from in-leakage based on statements from the Responsible Engineer. No areas were identified during the inspection or audit where groundwater was flowing through the Tendon Access Gallery walls. During a subsequent walkthrough of the Tendon Access Gallery on August 6, 2009 by engineering personnel, and another walkthrough with the NRC Regional Inspector on August 12, 2009, the floor was damp in a few areas with no accumulation of water which reinforces earlier discussion that the water on the floor during the April 24 inspection was due to rainwater. A sample of the water from a sump in the Tendon Access Gallery was analyzed on September 1, 2009 and the result showed the water was not aggressive (chlorides were 358 ppm; sulfates were 163 ppm; no pH reading taken).

Several types of deposits were noted by CR-3 during the NRC audit walkdown on July 15, 2009. Upon investigation, samples of these type deposits had been taken in March 2003 and analyzed. This 2003 analysis identified the leached white deposit, brown deposit and stalactite deposit as generally calcium carbonate (>98%) with the iron ≤ 0.04%. The pH was 10.5 and 10.7 recorded for the white and brown deposits only. The shiny white hard caulk like material was identified as 80% silica, 16% potassium, and 0.80% calcium as the main makeup of the material with 0.04% iron and a pH of 11.4.

Additional samples were also taken of the deposits on August 6, 2009. The white and brown deposits had to be scraped off the concrete with a metal scraper. The stalactite deposit was fragile and could be broken off or scraped off with a metal scraper. The shiny white hard caulk like material could be popped out of the concrete with a scraper which left a small void on the surface of the concrete. The leached white deposits and brown deposits were mainly calcium carbonate (> 95%), the stalactite deposit was predominantly calcium carbonate (> 80%) with a variance in the iron content (0%, 0.7%, and 0.29%). The pH varied from approximately 9.5 to 10. The shiny white hard caulk like material was identified as a mixture of calcium carbonate (~70%), potassium carbonate, silicon oxide, and potassium chloride. The pH was approximately 10.5. Each of the samples was saturated with water and the water tested for sulfates and chlorides. The sample from the stalactite deposit tested high for chlorides (1300 ppm). The chemistry analysis showed water in the Tendon Access gallery was non aggressive, the deposits were non aggressive except for the stalactite. This chemistry analysis information of the samples may prove useful for any additional investigations needed by Engineering.

The high alkalinity of concrete (pH > 12.5) provides an environment around embedded steel and steel reinforcement, which protects them from corrosion. If the pH is lowered, corrosion may occur. However, the corrosion rate is still insignificant until a pH of 4 .0 is reached. The degree to which concrete will provide satisfactory protection for embedded steel reinforcement depends in most cases on the quality of the concrete and the depth of concrete over the steel. The permeability of the concrete is also a major factor affecting corrosion resistance. Low water-to-cement ratios and adequate air entrainment increase resistance to water penetration and thereby provide greater resistance to corrosion. CR-3 used high density, low permeability concrete mix designs as discussed in LRA Subsection 3.5.2.2.2.2.5.

CR-3 plans to continue to manage the effect of aging so that the intended function of protecting the tendon anchorage hardware against corrosion is maintained by continuing to use the SMP and the ASME Section XI, Subsection IWL Programs. The programs have methodology to initiate corrective actions when unsatisfactory performance is determined. Plant inspections *have determined that satisfactory performance is being maintained consistent with the current licensing basis for the Tendon Access Gallery.*

RAI B.2.30-5

Background:

IN 2004-05 identified leakage of spent fuel pools at several existing nuclear power plants. The leak chase channels and associated piping were blocked by cementitious materials due to interaction with borated water.

Issue:

During a site walkdown of the spent fuel pool area on July 15, 2009, the staff observed that there was no leakage thru the leak chase channel piping located below the pool even though the valves on these piping were open. In addition, one of the pipe ends appeared to be blocked with cementitious material and boric acid crystals. Blockage of the leak chase channels can potentially cause leakage of the borated water from the spent fuel through the floor and walls of the spent fuel pool.

Request:

Provide a summary of the daily records of the leakage data collected at CR-3 spent fuel leak chase channel piping. The specific information required is as follows:

- When did the initial leakage of the leak chase piping stop?
- What action was taken to clean the leak chase piping?

This information is required to determine if there has been any degradation of the spent fuel pool concrete, liner, and rebar and how it will affect the integrity of the pool during period of extended operation.

Response

A review of daily operating logs through the time in question shows that several of the leak chase lines were reported as having ongoing leakage on the order of less than 1 drop/minute. While there were some leak chase lines that had some accumulation of boron at the outlet, there is no indication that any of the leak chases were plugged. Maintenance activities performed subsequent to the June 15 walkdown cleaned leak chase outlet piping and confirmed that the lines were not plugged.

Regarding IN 2004-05, subsequent to the Salem event, CR-3 initiated an investigation of fuel pool leakage and its implications on plant operations. The investigation concluded that:

- *CR-3 operating experience with spent fuel pool leakage has shown that leakage is minimal at the lower end of the spent fuel pool "normal" level range, but increases as level is raised to the upper end of the range. Accordingly, pool level is normally maintained to minimize liner leakage at very low levels.*

- *The CR-3 leak chases were physically verified as not clogged at that time. A snake was run up each of the 19 leak chases to verify they were clear. Preventive Maintenance activities were also initiated to periodically verify each of the leak chases are clear. These activities include analysis of samples of deposits removed for products of concrete degradation.*

RAI B.2.31-1

Background:

In LRA Section B.2.31, the applicant states that this is a new program and will be consistent with GALL AMP XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program. Under the Operating Experience (OE) Element, the applicant states that this program is a new program with no site specific OE history. However, under Element 4 of AMP B.2.31, the applicant states the CR-3 program utilizes plant OE to determine the plant areas to be inspected. It further states that based on this review of OE, the plant areas to be inspected become localized in nature, consisting of limited area (or subset) of a much larger plant area or zone. The corresponding GALL AMP XI.E1 program element states that a representative sample of accessible electrical cables and connections installed in adverse localized environment should be visually inspected for cable and connection jacket surface anomalies.

Issue:

It is not clear that Element 4 of the applicant's AMP is consistent with the corresponding element in the GALL AMP because the GALL Report recommends inspection of cables and connections installed in adverse localized environments while the applicant's AMP determines the areas to be inspected based on the plant OE.

Request:

Explain how the applicant AMP Element 4 is consistent with that in the GALL AMP, and how it will envelop electrical cables and connections in the scope of this aging management program.

Response

GALL recommends inspection of cables and connections installed in adverse localized environments. An adverse localized environment is a condition in a limited plant area that is significantly more severe than the specified service environment for the cable and connection. The CR-3 AMP utilizes operating experience (OE) to establish where adverse localized environments (ALEs) may exist to determine the plant areas to be inspected. OE covers a wide range of plant-specific documents and industry related guidance. Site-specific OE includes the use of EQ zone maps, environmental surveys, maintenance records, corrective actions and conversations with plant personnel to establish where ALEs may exist based on past cable failures, cables that exhibited the effects of aging, areas of localized overheating, hot spots, etc. Industry guidance documents include EPRI TR-109619 and EPRI TR-1003317 which provide guidance for locating and identifying ALEs, and establishing an effective methodology for field walkdown of cable systems.

RAI B.2.32-1

Background:

In the basis document L08-0641, "License Renewal Aging Management Program Description of Electrical and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program," under Detection of Aging Effects, the applicant states that as an alternate to the review of calibration or surveillance results, CR-3 will test the cable system used in the power range (PR) circuits of the excore monitoring system. In the corresponding GALL AMP element, states that in cases where a calibration or surveillance program does not include the cable system in the testing circuit, the applicant should perform cable system testing for detecting deterioration of the insulation system.

Issue:

GALL AMP XI.E2 recommends testing of cable system in nuclear instrumentation circuits disconnected during the calibration or surveillance procedures. The licensee's basis document, L08-0641, allows calibration of instrumentation system with the cable system disconnected during surveillance or calibration procedures.

Request:

Explain how the CR-3 AMP is consistent with the corresponding GALL AMP XI.E2 for detecting cable system deterioration.

<u>Response</u>

LRA Appendix A, Section A.1.1.32, and Appendix B, Section B.2.32, specifically state that the power range cable systems used in the Excore Monitoring System will be tested, which is consistent with GALL AMP XI.E2. The CR-3 basis document L06-0641, License Renewal Aging Management Program Description of Electrical and Connections Not Subject to 10 CFR 50.49 environmental Qualification Requirements Used in Instrumentation Circuits Program, in the discussion of the GALL element "Detection of Aging Effects" specifically requires testing of the power range cables. L06-0641 provides the basis for LRA Appendix A, Section A.1.1.32, and Appendix B, Section B.2.32.

RAI-B.2.35-1

Background:

For LRA AMP B.2.35, Program Element 3 (Parameters Monitored/Inspected) the applicant states, "Loss of continuity due to corrosion and oxidation will be managed by the Fuse Holder Program. Fatigue due to ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, and chemical contamination are not applicable aging effects for CR-3 fuse holders located outside of active devices."

Issue:

GALL AMP XI.E3 states that this program element recommends monitoring thermal fatigue in the form of high resistance caused by ohmic heating, thermal cycling or electrical transients, mechanical fatigue caused by frequent removal/replacement of the fuse or vibration, chemical contamination, corrosion, and oxidation.

Request

Provide justification for eliminating the monitoring of thermal fatigue in the form of high resistance caused by ohmic heating, thermal cycling or electrical transients, mechanical fatigue caused by frequent removal/replacement of the fuse or vibration, and chemical contamination from LRA AMP B.2.35.

Response

CR-3 fuse holders subject to AMR are used in control valve and/or intermittent instrumentation and control (I&C) applications. The only fuses that could potentially be exposed to thermal cycling and ohmic heating are those that carry significant current in power supply applications. I&C circuits characteristically operate at such low currents that no appreciable thermal cycling or ohmic heating occurs. Since thermal cycling and ohmic heating apply to power supply applications, they are not considered applicable aging mechanisms for CR-3 fuse holders. The CR-3 electrical design ensures that stresses due to forces associated with electrical faults and transients are mitigated by the fast action of circuit protective devices at high currents. Mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature. CR-3 fuses are not routinely pulled and/or manipulated to facilitate plant testing. Therefore, frequent manipulation is not considered an applicable aging mechanism. Vibration is induced in fuse holders by the operation of external equipment, such as compressors, fans, and pumps. Plant walk-down has verified that there are no direct sources of vibration for the fuse holder panels, and the panels are mounted separately to their own support structure on a concrete wall or column. Therefore, vibration is not considered an applicable aging mechanism. Plant walkdown has also verified that there are no potential sources of chemical contamination in the area and that the fuse holders are totally enclosed in a protective junction box which would provide protection even if chemical contamination were possible.

RAI B.3.1-1

Background:

LRA Section B.3.1 states that the CR-3 reactor coolant pressure boundary (RCPB) Fatigue Monitoring Program relies on monitoring and tracking the significant thermal and pressure transients for limiting RCPB components to prevent the fatigue design limit from being exceeded.

Issue:

The LRA provides no description or discussion regarding how CR-3 has been and will be monitoring the severity of pressure and thermal (P-T) activities during plant operations. It is essential that all thermal and pressure activities (transients) are bounded by the design specifications (including P-T excursion ranges and temperature rates) for an effective and valid aging management program.

Request:

1. Describe the procedure methods that CR-3 uses for tracking thermal transients.

2. Confirm that all monitored transient events are bounded by the design specifications.

3. Specify the time (years) over which actual transient monitoring and cycle tracking activities took place. If there have been periods for which transient events were not monitored since the initial plant startup, specify the affected time frame, and provide justification to demonstrate that the estimated cycles for this unmonitored period are conservative.

Response

1. *CR-3 uses an existing plant procedure to document transients and cycles on applicable systems so that the limits imposed by Technical Specifications and the FSAR are not exceeded. The procedure requires a review of plant operating data and a comparison of each transient to the transients defined in the design documents. All partial cycles are recorded as a complete cycle unless appropriate analysis and documentation is provided.*

2. *CR-3 has and will continue to monitor the severity of pressure and thermal activities during plant operations as follows:*
   - *For each recorded event, the procedure requires a comparison to the design transients. Based on the results of the comparison, a determination is made as to which design transient has occurred.*
   - *Events are evaluated to determine whether it is necessary to log several transient cycles.*

   If an event were to occur that is not bounded, CR-3 would initiate a condition report as part of the Corrective Action Program and perform an evaluation in accordance with site quality assurance procedures that meet 10 CFR 50 Appendix B requirements.

3. *This program has been in place since the issuance of the CR-3 operating license.*

RAI B.3.1-2

Background:

LRA Section B.3.1, Operating Experience element, states that CR-3 performed a review of NRC generic communications (including Information Notices, Bulletins, Generic Letters, and draft generic communication), the Institute of Nuclear Power Operations OE database, and Licensee

Event Reports, and identified no applicable OE items that relate to fatigue monitoring or to exceeding fatigue design limits.

Issue:

Page 15 of the AMP basis document L08-0604 indicates that CR-3's review of the NRC generic communications only covered the time since January 2005. It is unclear to the staff why the coverage was limited to such a short period. Industry OE reported in the earlier dates are just as valuable and important as the recently found ones and thus should be taken into consideration in developing effective aging managing programs also. For example, NRC Bulletin 88-08 affects all nuclear power reactors, and NRC Bulletin 88-11 affects all PWR plants. The issues and the unanticipated transients described in 88-08 and 88-11 are related to fatigue monitoring.

In addition, the onsite basis document states that "high cycle fatigue due to vibration is not germane to fatigue management program focused on tracking cycles and transients related to low cycle fatigue" and concluded that the OE on cracking/leaking in South Texas Project 2, Hope Creek, and St. Lucie 2 are not applicable to CR-3. It is unclear to the staff why the CR-3 fatigue AMP excludes high cycle fatigue effects.

Request:

1. Provide CR-3's review criteria that led to the conclusion as stated: "no applicable OE items that relate to fatigue monitoring or to exceeding fatigue design limits."

2. Describe the action that CR-3 continues to take in response to the NRC Bulletin 88-08.

3. Describe the action that CR-3 continues to take in response to the NRC Bulletin 88-11.

4. Provide basis that high cycle fatigue can be exempted from AMP when high cycle fatigue can also raise safety concerns, especially when high-cycle fatigue due to flow-induced vibrations is addressed in LRA Section 4.3.1.2 for the reactor vessel (RV) internal components.

<u>Response</u>

1. *NUREG-1801, Revision 1, is the repository of industry operating experience up to the time the draft was issued for public comment (January 28,2005, see ADAMS Accession Numbers ML050270004 and ML050270052). Therefore, the process for reviewing industry operating experience includes the time period from January, 2005 up to and including the date of the preparation of the basis document. The following data sources were reviewed for that time period:*

    - *NRC Bulletins*
    - *NRC Generic Letters*
    - *NRC Information Notices*
    - *Regulatory Issue Summary 2008-30*
    - *Licensee Event Reports (keyword search for "fatigue")*
    - *INPO Operating Experience Database (keyword search for "fatigue")*

Plant-specific operating experience was also reviewed. The results of these reviews led to the conclusion that there were no operating experience items related to exceeding fatigue design limits.

2. *The applicable components associated with this bulletin are the HPI/Makeup Nozzles and Thermal Sleeves. CR-3 committed to perform augmented inspections on these components. These inspections are used to confirm nozzle and thermal sleeve integrity. A description of these inspections is contained in CR-3's ISI Components and Structures Examination Program.*

3. *CR-3 has included the subject thermal events in the fatigue evaluations to ensure ASME Code compliance. Refer to RAI 4.3.1.6-1 for a more complete discussion.*

4. *High cycle fatigue is not a concern for License Renewal since it would be discovered during the current license period in most cases where systems are frequently operated, as is supported by the following discussion of NRC Information Notice (IN) 2002-26, "Failure of Steam Dryer Cover Plate after a Recent Power Uprate." This information notice alerted licensees of failure of a steam dryer cover plate during operation following a power uprate at a boiling water reactor (BWR). In March 2002, a BWR completed a refueling outage which included a modification to add baffle plates to the steam dryer to reduce the excessive moisture carryover expected as a result of an extended power uprate. In June 2002, the unit began experiencing fluctuations in steam flow, reactor pressure and level, and moisture carryover in the main steam lines. The licensee discovered that a dryer cover plate on the outside of the steam dryer had broken loose. Preliminary results of scale model testing indicated that the failure of the plate was due to high cycle fatigue driven by flow-induced vibration. This fatigue was attributed to excessive vibration caused by the synchronization of the cover plate resonance frequency, the nozzle chamber standing acoustic wave frequency, and the vortex shedding frequency. The licensee concluded that the three frequencies synchronized in a very narrow band of steam flow at or near the steam flow required to reach full power under the power uprate. This experience supports high cycle fatigue being a design issue and not a license renewal concern.*

   Concerning the evaluation of the reactor internals for flow-induced vibration endurance limit assumptions, CR-3 disposed of this particular TLAA using 10 CFR 54.21(c)(1)(ii) – The analysis has been projected to the end of the period of extended operation not 10 CFR 54.21(c)(1)(iii) – The effects of aging on the intended function(s) will be adequately managed for the period of extended operation. Therefore, this TLAA is specifically not managed by the program described in B.3.1.

RAI B.3.1-3

Background:

LRA Section B.3.1, Operating Experience element, states that CR-3 has reviewed the EPRI "Good Practice" documents related to fatigue and revealed that the CR-3 fatigue AMP is in accordance with the "Good Practice" recommendations.

Issue:

Additional information relating to the EPRI "Good Practice" is needed to enable the staff to perform its evaluation.

Request:

Provide a summary of the EPRI "Good Practice" (including EPRI report number) and demonstrate that the CR-3's fatigue monitoring program is consistent with the "Good Practice" recommendations.

Response

The EPRI Materials Reliability Program (MRP) issued technical report TR-1012018 entitled, "Thermal Fatigue Licensing Basis Monitoring Guideline (MRP-149)." This document provides guidance for utility engineers in the implementation of fatigue monitoring that will adequately and economically track the effects of fatigue on significant reactor coolant pressure boundary components during plant operations through the current licensing period and an extended license period. Following this guideline will ensure the continued maintenance of the plant fatigue licensing basis. The EPRI report has been released as a "good practice" document, in accordance with the NEI 03-08 materials initiative protocol. An action request was issued in accordance with Progress Energy's procedure related to industry group membership to track its implementation. The requirements for Nuclear Energy Institute (NEI) Industry Initiative on the Management of Materials Issues have been incorporated into a corporate procedure. This action request performed a review of CR-3's program and determined that it was in compliance with the recommendations.

RAI B.3.1-4

Background:

LRA Section B.3.1 states that the CR-3 Reactor Coolant Pressure Boundary (RCPB) Fatigue Monitoring Program will address the effects of the reactor coolant environment on component fatigue life at the sample locations identified in NUREG/CR-6260.

Issue:

It is unclear to the staff whether this feature has already been implemented in the CR-3 RCPB Fatigue Monitoring Program at the time of its license renewal application.

Request:

Confirm the status requested. If this feature has not yet been implemented, pursuant to the GALL Report requirements, it is necessary to make a license renewal commitment that the RCPB Fatigue Monitoring Program will be enhanced by monitoring the six component locations identified in NUREG/CR-6260 applicable to CR-3.

Response

The Reactor Coolant Pressure Boundary Fatigue Monitoring Program as currently implemented bounds the locations identified in NUREG/CR-6260.

RAI B.3.1-5

Background:

CR-3 onsite basis document, L08-0604, states that the CR-3 RCPB Fatigue Monitoring Program Element 2, preventive action, is given an "alarm limit" feature that will be initiated when transient cycles in any category reaches 90% of the allowable value.

Issue:

It is unclear to the staff whether this feature has already been implemented in the CR-3 RCPB Fatigue Monitoring Program at the time of its license renewal application.

Request:

Confirm the status requested. If this feature has not yet been implemented, pursuant to the GALL Report requirements, it is necessary to make a license renewal commitment that the RCPB Fatigue Monitoring Program will be enhanced by providing the "alarm limit" capability.

Response

The Reactor Coolant Pressure Boundary Fatigue Monitoring Program as currently implemented contains the described "alarm limit" feature.

RAI 4.3.1-1

Background:

In LRA Section 4.3.1, the applicant states that CR-3 performed an assessment of the number of nuclear steam supply system (NSSS) design transients that have occurred through December 2007 to determine the margin between the number of accrued cycles and the original 40-year design cycles. In addition, the applicant states that CR-3 has performed an assessment of the impact of the measurement uncertainty recapture 1.6 percent power uprate.

Issue:

Despite the statement indicated, throughout the whole LRA, no such data as the "accrued cycles" could be found. It is essential that the LRA provides the number of the accrued cycles to the date near its license renewal application submittal for all significant transients so as to facilitate future cycle prediction and management during the extended operation period. In addition, through the whole LRA, there is no discussion on the impact of the uprated power on the NSSS design transients.

Request:

1. Provide data of the accrued cycles for all transients that are managed and monitored under the CR-3 RCPB Fatigue Monitoring Program.

2. Describe how CR-3 assessed the measurement uncertainty recapture 1.6% power uprate and the impact of the power uprate on the NSSS design transients.

Response

1. *The response to RAI 4.3.1-2, part 1, provides the accrued cycles for all transients that are managed and monitored under the CR-3 RCPB Fatigue Monitoring Program.*

2. *In support of power uprate applications in 2002 and 2007, AREVA NP reviewed the impact of CR-3 uprated plant conditions relative to the NSSS design transients. The results of these evaluations were documented in the respective license amendment requests (Section 5.0 of License Amendment Request #270, ADAMS Accession Number ML021640547, dated June 5, 2002, and Section 4.0 of License Amendment Request #296, ADAMS Accession Number ML071220227, dated April 25, 2007). These evaluations determined that the impacts of power uprate (2002 and 2007) design conditions remain within the design conditions of the Reactor Coolant System (RCS) functional specification; and the proposed change will not result in any new design transients or adversely affect the current CR-3 design transient analyses. The license amendment requests were approved as documented in the issuance of Amendments 205 (ADAMS Accession Number ML023380800) and 228 (ADAMS Accession Number ML073600419) to the facility operating license, respectively.*

RAI 4.3.1-2

Background:

In LRA Section 4.3.1, the applicant states that based on 30 years of plant operating experience, for CR-3, there is considerable margin on the NSSS design transient cycles originally designed for 40 years and there is no need to increase the number of NSSS design transients for the period of extended operation. The applicant then made its 60-year projections on CUFs and transient cycles simply by multiplying a factor of 1.5 on both the 40-year CUFs and the design NSSS transient cycles.

Issue:

LRA Table 4.3-2, which contains the design fatigue usage factors (CUF, 40-year usage), shows that there are many locations that have CUF values greater than 0.67. Multiplying by 1.5 and these locations will have their CUF values greater than the limit of 1.0 during the extended operation period – inconsistent with the applicant's claim that there is considerable margin on design transient cycles and there is no need to increase the number of design transients for the period of extended operation.

Request:

1. Please provide the basis for the statement that there is considerable margin on the NSSS design transient cycles, and make necessary conforming corrections to the LRA.

2. Clarify whether the CUFs for the pressurizer nozzle, surge line hot leg nozzle and surge line elbows and piping as shown in Table 4.3-2 have included the insurge/outsurge and the stratification transients.

Response

1. *A review of the accrued cycles, shown in parentheses in the last column of the following table, indicates that in 31 years of operation no transient has exceeded 40% of its allowable limit.*

   As shown in Enclosure 2, the last three sentences of the third paragraph on page 4.3-2 of the LRA will be deleted to remove references to the factor of 1.5. Conforming changes to the LRA will be made to Subsections 4.3.1.1 through 4.3.1.7 and 4.3.2.1.

2. *Yes. More detail has been provided in the response to RAI 4.3.1.6-1.*

Table of Accrued NSSS Design Transient Cycles for RAI 4.3.1-2 Response

ID. No.	*Transient Description*	*40-Year Design Cycles (Cycles accrued through 12/31/2007)*
1A	*RCS Heatup 70°F to 557°F at 100 °F/hr*	*240 (87)*
1B	*RCS Cooldown 557°F to 70°F at 100 °F/hr*	*240 (86)*
7	*Step Load Reduction (100% to 8% Power)* *Resulting from Turbine Trip* *Resulting from Electrical Load Rejection*	 *160 (7)* *150 (7)*
8	*Reactor Trips* *Resulting from Loss of All Reactor Coolant Pumps* *Due to Turbine Trip Without Automatic Control Action* *Resulting from Complete Loss of All Main Feedwater* *Included in Transients 11, 15, 17A, and 17B*	 *40 (2)* *160 (2)* *88 (6)* *110 (14)*
9	*Rapid Depressurization (2,200 psi to 300 psi in 1 hr)*	*40 (0)*
10	*Change of Flow (Loss of One or More Reactor Coolant Pumps)*	*20 (8)*
11	*Rod Withdrawal Accident*	*40 (1)*
12	*Hydrostatic Tests at 3,125 psig* *RCS Components (Primary Side)* *OTSG A (Secondary Side)* *OTSG B (Secondary Side)*	 *20 (1)* *35 (2)* *35 (2)*
15	*Loss of Station Power*	*40 (5)*
17A	*Loss of Feedwater to One OTSG*	*20 (8)*
17B	*Stuck Open Turbine Bypass Valve*	*10 (0)*
22	*High Pressure Injection Valve Test*	

ID. No.	Transient Description	40-Year Design Cycles (Cycles accrued through 12/31/2007)
	Actuation of Makeup Valve MUV-23	*40 (13)*
	Actuation of Makeup Valve MUV-24	*40 (12)*
	Actuation of Makeup Valve MUV-25	*40 (13)*
	Actuation of Makeup Valve MUV-26	*40 (13)*
22	*Core Flooding Check Valve Test*	
	Core Flood Tank CFT-1A	*240 (27)*
	Core Flood Tank CFT-1B	*240 (28)*
8	*High Pressure Injection Actuations*	
	MUV-23	*11 (4)*
	MUV-24	*11 (4)*
	MUV-25	*11 (2)*
	MUV-26	*11 (2)*
No ID	*High Pressure Auxiliary Pressurizer Spray*	*15 (0)*
14	*Control Rod Drop*	*40 (10)*
25	*Refill of Hot, Dry Depressurized OTSG*	
	OTSG A	*50 (0)*
	OTSG B	*50 (0)*
26	*Emergency Feedwater Actuation*	
	Flow Initiation to OTSG A Upper Feed Nozzles	*1510 (506)*
	Flow Initiation to OTSG B Upper Feed Nozzles	*1510 (371)*

RAI 4.3.1.1-1

Background:

In LRA Section 4.3.1.1, the applicant disposes its TLAA for the RV components to 10 CFR 54.21(c)(1)(iii).

Issue:

It is unclear to the staff whether the disposition herein is meant to apply to all components of the RV, or only meant to apply to the only component that is projected to have its 60-year CUF exceed the limit. Uncertainty such as this one is seen in several other subsections under Section 4.3.

Request:

Clarify the uncertainty at the conclusion of Section 4.3.1.1 and other subsections that have the same uncertainty.

Response

Based on the response to RAI 4.3.1-2, the analysis and disposition of this TLAA is as follows:

Analysis

For the components that are part of the RV, the maximum CUF is that of the Lower Service Support Structure attachment weld with a CUF of 0.72. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation.

Disposition: *10 CFR 54.21(c)(1)(i) – The analyses remain valid for the period of extended operation.*

RAI 4.3.1.2-1

Background:

In LRA Section 4.3.1.2, five places show improbable number of cycles as basis to describe the endurance limit of fatigue life. Specifically, as appeared in the LRA, these are 1012, 106, 1012, 1013, and 1011 cycles.

Issue:

This is most likely formatting error. Endurance limit for metals usually are greater than 10^6 cycles. In addition, the LRA lacks the information about the material of the components considered for the FIV related high cycle fatigue analysis, and the maximum alternating stress (S_a) that was calculated in Report BAW-10051.

Request:

1. Correct the errors on the cycles accordingly.
2. Specify the material, temperature, and maximum alternating stress used in BAW-10051 for the fatigue analysis.
3. Provide the figure number and curve number of the ASME design S-N fatigue curve used for the endurance limit determination described in the LRA. Provide also the basis of choosing the fatigue curve used in your endurance limit calculation and the results.

Response

1. *The revised LRA text in Subsection 4.3.1.2 is as follows and as shown in Enclosure 2:*

   FIV Endurance Limit Assumptions

   BAW-10051 calculated stress values for the redesigned RVI and compared them to endurance limit stress values. These endurance limit values were based on an assumed value of 10^{12} cycles for 40 years of operation. Since the fatigue curves at the time of design only went up to 10^6 cycles, these curves were extrapolated to 10^{12} cycles. The methodology used in BAW-10051 was extended from 40 years to 60 years by multiplying the assumed endurance limit cycles by 1.5 and then using 10^{13} cycles to determine the endurance limit based on more recent ASME fatigue curves which extend *now to 10^{11} cycles (Figure 1-9.2.2 of ASME Section III, 1986 Edition). The component item stress values in BAW-10051 were compared to the recalculated endurance limit values and were shown to be acceptable. Therefore, the FIV analysis has been projected to the end of the period of extended operation.*

2. *The scope of BAW-10051, "Design of Reactor Internals and Incore Instrument Nozzles for Flow Induced Vibration," September 1, 1972, included nickel based alloy reactor vessel instrument nozzles and the following reactor vessel internals subassemblies made from stainless steel and nickel based alloy: flow distributor assembly, thermal shield, surveillance holder tube assembly, and inlet baffle. BAW-10051, Supplement 1, included an update to the structural evaluation of the redesigned surveillance holder tube assembly. Reactor vessel internals non-bolting subcomponents are fabricated from stainless steel; high strength bolting is fabricated from stainless steel or nickel based alloy. The supporting evaluation for the text in Section 4.3.1.2 of the CR-3 LRA is provided below.*

   In the BAW-10051 and BAW-10051, Supplement 1 analyses, the highest zero-to-peak alternating stresses due to FIV are compared with an extrapolated endurance limit for 10^{12} cycles, which was the number of cycles postulated for a 40-year plant life. Since the highest number of cycles in both the austenitic steel and ferritic steel fatigue curves was 10^{6} (at that time), an extrapolation of the endurance limit was performed and is reported in Appendix A of BAW-10051 and is explained below.

   The consensus was that the fatigue curve decreases at a rate of approximately 4% per decade of cycles beyond 10^{6}. The 40-year endurance limits (based on a 4% per decade rate decrease) are calculated as follows:

   <u>For the stainless steel and nickel based alloy non-bolting internals items:</u>

   Endurance limit for 10^{6} cycles: 26,000 psi.
   Endurance limit for 10^{12} cycles (number of cycles for 40 years):
   *$(0.96)^{6}$ * 26.000 psi = 20,400 psi, which was reduced to 18,000 psi.*

   <u>For the high-strength bolting:</u>

   Endurance limit for 10^{6} cycles: 13,500 psi.
   Endurance limit for 10^{12} cycles (number of cycles for 40 years):
   *$(0.96)^{6}$ * 13,500 psi = 10,570 psi.*

   *As mentioned above, a number of 10^{12} cycles was postulated for the 40-year plant life. For the 60-year plant life, the number of cycles to be postulated would be 1.5 * 10^{12} cycles. However, 10^{13} cycles is considered.*

   In addition, a multiplication factor of 0.9 is considered for the thermal adjustment of the fatigue curve (the Young's modulus E at 100% power operating temperature of ~600 °F is approximately 10% smaller than Young's modulus at room temperature).

   The austenitic steel ASME fatigue curves have been extended (starting with the 1983 Edition) from 10^{6} cycles to 10^{11} cycles. The "extended" Curves A, B, and C are shown in Figure 1-9.2.2 of ASME Section III, 1986 Edition, Appendices, with the stress values *listed in Table I-9.2.2. From Curves A, B, and C, the most severe Curve C does not need to be considered as it only applies to primary plus secondary stress ranges higher than 27, 200 psi (the highest peak stress range for the internals is equal to 2 * 11,500 psi = 23,000 psi.; see Redesigned Surveillance Specimen Holder Tube in Table below). Therefore, the next most severe Curve B is considered.*

The 60-year endurance limits are calculated assuming 10^{13} cycles follows:

<u>For the stainless steel and nickel based alloy non-bolting internals items:</u>

10^{11} cycles endurance limit = 16,500 psi.
(ASME III, 1986 Edition, Appendices, Table 1-9.2.2, Curve B)
10^{13} cycles endurance limit = $0.9 * (0.96)^2 * 16{,}500$ psi = 13,700 psi, (including thermal adjustment)

<u>For the high-strength bolting:</u>

10^6 cycles endurance limit = 13,500 psi.
(ASME III, 1986 Edition, Appendices Table 1-9.4. with Maximum Nominal Stress $< 2.7 *S_m$)
10^{13} cycles endurance limit = $0.9 * (0.96)^7 * 13.500$ = 9,100 psi, (including thermal adjustment)

Note that in the extrapolation for the reduction of the endurance limit the factor of 0.96 has been considered since the ASME fatigue curves are essentially constant at high cycles (e.g., 10^{12} cycles).

The Table below provides a summary of comparisons of maximum alternating stress values from BAW-10051 and BAW-10051, Supplement 1, with their allowable values, before and after reduction of these allowable values for consideration of a 60-year plant life. Only the limiting items (i.e., thermal shield bolts and redesigned surveillance specimen holder tubes) are reported at 60 years in Table 1. As shown in the Table for the limiting item at 60-years (i.e., redesigned surveillance specimen holder tube), the alternating stress value is smaller than the allowable by at least 19%.

RAI 4.3.1.2-1 Response Table — Summary of FIV Maximum Alternating Stress Values from BAW-10051 and from BAW-10051, Supplement 1			
Item	***S_{alt}, psi***	***S_a (all), psi***	***S(all)/S_{alt}***
BAW-10051 40-year results			
Incore Instrumentation Nozzle	*7,000*	*18,000*	*2.57*
Incore Instrumentation Guide Tubes			
Cantilevered Portion below flow distributor	*3,950*	*18,000*	*4.56*
Between flow distributor and support plate	*3,050*	*18,000*	*5.90*
Between support plate and spider casting	*2,030*	*18,000*	*8.87*
Gusset welds	*3,125*	*18,000*	*5.76*
J-groove welds	*4,225*	*18,000*	*4.26*
Flow Distributor			
Ligament stresses	*5,815*	*18,000*	*3.10*
Support Plate ledge area	*3,635*	*18,000*	*4.95*
Flow distributor assembly to lower grid assembly	*2,015*	*18,000*	*8.93*

RAI 4.3.1.2-1 Response Table — Summary of FIV Maximum Alternating Stress Values from BAW-10051 and from BAW-10051, Supplement 1			
Flow Distributor Assembly Support Plate			
Ligament stresses	*3,985*	*18,000*	*4.52*
Thermal Shield			
Upper Support Bolts	*7,425*	*10,570*	***1.42***
Upper Support Blocks	*8,260*	*18,000*	*2.18*
Lower Support Bolts	*6,800*	*10,570*	***1.55***
Surveillance Holder Tube	*1,130*	*18,000*	*15.93*
Inlet Baffle	*6,912*	*18,000*	*2.60*
Redesigned Surveillance Specimen Holder Tubes-BAW-10051, Supplement 1 for 40-years			
Bracket	*9,500*	*18,000*	***1.89***
Tube	*11,500*	*18,000*	***1.57***
Capsule	*2,000*	*18,000*	*9.00*
Consideration of the reduced endurance limits S_a (all) for limiting items for 60-year plant life. Limiting items with S_a/S_{alt} < 2.0			
Thermal Shield			
Upper Support Bolts	*7,425*	*9,100*	*1.23*
Lower Support Bolts	*6,800*	*9,100*	*1.34*
Redesigned Surveillance Specimen Holder Tubes			
Bracket	*9,500*	*13,700*	*1.44*
Tube	*11,500*	*13,700*	*1.19*

3. *The ASME figure numbers are provided in the response to part 2, above.*

RAI 4.3.1.3-1

Background:

In LRA Section 4.3.1.3, the applicant states that metal fatigue was considered in the design of the "Type C" control rod drive mechanism (CRDM) motor tube. However, the LRA also states that CUF of the CRDM motor tube was not calculated because the motor tube did not require analysis for cyclic operation in accordance with ASME Section III, paragraph N-415.1. In addition, the LRA also states that the NSSS design transients for CR-3 have not been increased for the period of extended operation. This same statement regarding the design cycles also appears in Section 4.3.1.4.

Issue:

It was uncertain to the staff whether CR-3 CUF for the CRDM motor tube was calculated or not. In addition, in LRA Section 4.3.1, the applicant states that the transient cycles are multiplied by a factor of 1.5 for the period of the extended operation.

Request:

1. Clarify whether the CUF analysis for the CRDM motor tube was completed.

2. Describe how ASME III Paragraph N-415.1 endorses exemption of fatigue usage calculation for the CRDM motor tube.

3. Provide basis that the transients for CR-3 are not increased for the period of extended operation. If the statement is false, correct accordingly for Sections 4.3.1.3 and 4.3.1.4.

Response

1. *As stated in Section 4.3.1.3 of the CR-3 LRA, CUFs of the CRDM motor tube were not calculated; as it was shown that the motor tube did not require analysis for cyclic operation in accordance with ASME Section III, 1965 Edition, with Addenda through 1967, Paragraph N-415.1. Since all conditions of Paragraph 415.1, items (a) through (f), were satisfied, design for cyclic loading in accordance with Paragraph N-415.2 was not required.*

2. *The CRDM Type C stress report was reviewed and it was confirmed that NSSS design transients (i.e., number of cycles and/or transient definitions) were used to show compliance to the conditions specified in Paragraph N-415.1, items (a) through (e). The CRDMs are connected to the reactor vessel CRDM nozzles and no pipe reactions were identified; therefore, N-415.1(f) is not applicable. Since CR-3 is not revising the number or definition of NSSS design transients, Paragraph N-415.1, items (a) through (f), are acceptable for the period of extended operation. The stress report is available at the CR-3 site for review.*

3. *See response to RAI 4.3.1-2 for the basis that the number of design transients need not be increased for the period of extended operation.*

RAI 4.3.1.4-1

Background:

In LRA Section 4.3.1.4, the applicant reviewed the transients and fatigue evaluations for various parts of the reactor coolant pump (RCP) and disposes the TLAA for the RCP locations in accordance with both 10 CFR 54.21(c)(1)(i) and 10 CFR 54.21(c)(1)(ii).

Issue:

The regulatory disposition statements should be part specific if not all parts of the analysis group consistently fall in the same disposition class.

Request:

Identify which part or locations of the RCP are managed in accordance with 10 CFR 54.21(c)(1)(i) and which are managed in accordance with 10 CFR 54.21(c)(1)(ii).

Response

As described in the response to RAI 4.3.1-1, the NSSS design transients will not be revised for the period of extended operation. Therefore, the CUF calculations for the casing, cover and *lower shaft performed in accordance with N-415.2, and the exemption from fatigue evaluations for the seal and heat exchanger performed in accordance with N-415.1(a) through N-415.1(f) remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). For additional information, see the response to RAI 4.3.1-2, part 1.*

RAI 4.3.1.6-1

Background:

LRA Section 4.3.1.6 presents the fatigue TLAA for the pressurizer and shows the design fatigue values (40-year CUF) in Table 4.3-2.

Issue:

The LRA made no mention with regard to CR-3's position on stratification and insurge/outsurge events for pressurizer surge lines and response NRC Bulletin 88-11 that requires all PWR plants to include these thermal events in the fatigue evaluations to ensure ASME Code compliance.

Request:

1. Confirm whether the fatigue evaluations for the pressurizer surge nozzle including lower head region, surge line piping, and surge line hot leg nozzle have taken stratification and insurge/outsurge events into account.

2. Discuss how CR-3 reconstructed the heatup and cooldown cycles that occurred prior to December 20, 1988 (the date of issuance for Bulletin 88-11) for the pressurizer surge line stratification and insurge/outsurge events before the dates of issuance of NRC Bulletins 88-08 & 88-11.

<u>Response</u>

1. *Section 4.3.1.6 of the CR-3 LRA addresses the pressurizer and includes the attached nozzles, including the recently completed weld overlay for the pressurizer surge nozzle. Section 4.3.1.7 of the CR-3 LRA addresses all RCS piping and includes the surge line piping and surge line hot leg nozzle. Structural evaluations for the pressurizer surge nozzle, surge line and hot leg surge nozzle are described in BAW-2127, "Babcock & Wilcox Owners Group, Final Submittal for Nuclear Regulatory Commission Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." The effects of thermal stratification in the lower head of the pressurizer is included in the cumulative usage factors reported in Table 4.3-2 of the CR-3 LRA for the pressurizer.*

2. *The construction and characterization of heatup and cooldown cycles that occurred prior to IEB 88-11 is described in Section 4.5 of BAW-2127. Heatups prior to IEB 88-11 were categorized into Groups 1A1 through 1A3 based on review of plant-specific data (see BAW-2127, Page 4-18 and Table 4-2). Heatups after IEB 88-11 were categorized as either 1A4 or 1A5. Cooldowns were categorized as 1B1 or 1B2 (BAW-2127, Page 4-24). Based on a review of plant data, approximately 15% of cooldown events prior to IEB 88-11 were categorized as type 1B1. The remainder of events prior to IEB 88-11*

were included in type 1B2. Cooldowns after IEB 88-11 were categorized with 15% as type 1B1 and the remaining 85% as type 1B2.

RAI 4.3.2.1-1

Background:

LRA Section 4.3.2.1 shows the fatigue TLAA for the USAS B31.1.0 Class 1 piping. The section was divided into two parts. For the first part, it states that "Since the transient set (and associated cycles) in the Reactor Coolant System (RCS) Functional Specification is being maintained, the analytical basis for these components remains unchanged." It then concluded that the TLAA for these components remain valid for the period of extended operation. Additionally, LRA Section 4.3.2.2 shows the fatigue TLAA for the USAS B31.1.0 Non-Class 1 piping. The applicant concluded that the TLAA for the portion of the Non-Class 1 piping components where the cycles are unrelated to the heatups and cooldowns can be projected to the end of the period of the extended operation.

Issue:

Adding the cycles from all transients shown in Table 4.3-1, the staff obtained 4957. To avoid double counting, the staff excluded 110 cycles from Transient 8d because this transient has been accounted in Transients 11, 15, 17A and 17B. In addition, the staff treated the heatup-cooldown as single events and so 240-cycle was counted only once. Multiplying 4957 by 1.5 and one obtains 7436 cycles for 60 years, which exceeds the 7000 cycles limit. However, the applicant did not make a required appropriate reduction to the allowable stress range. Similar situation occurs to a portion of the Non-Class 1 piping (LRA Section 4.3.2.2), namely, the portion where the cycles are unrelated to the heatup and cooldown transients. The 60-year cycles for these Non-Class 1 components also exceed the 7000 cycle limit, even though 240 cycles from the paired heatup-cooldown transients have been subtracted, but the applicant did not make a required appropriate reduction to the allowable stress range.

Request:

1. Please provide justification that the TLAA for the Class 1 piping components remain valid for the period of extended operation, 10 CFR 54.21(c)(1)(i).
2. Please provide justification that the TLAA for the portion of the Non-Class 1 piping components where the cycles are unrelated to the heatups and cooldowns can be projected to the end of the period of the extended operation, 10 CFR 54.21(c)(1)(ii).

<u>Response</u>

1. *The response to RAI 4.3.1-2 provides a discussion supporting the conclusion that the design transient set will not be exceeded. In addition, the LRA will be revised to delete references to the factor of 1.5. Therefore, summing the transients as proposed in this RAI does not exceed the 7,000 cycle limit.*
2. *The response to RAI 3.3.2.2.1-1 provides a complete discussion on the qualification of components whose cycles do not track with heatups and cooldowns.*

RAI 4.3.3-1

Background:

LRA Section 4.3.3 discusses the environmentally assisted fatigue evaluation. On Page 4.3-12, it states that "Evaluations at all locations are based on application of environmental penalty factors to the ASME 40-year CUF values".

Issue:

Based on the CUF projection method described at the beginning of LRA Section 4.3, the projected 60-year CUF is 1.5 times the 40-year CUF value for each location. Therefore, environmentally assisted fatigue calculated based on 40-year CUF value as stated in LRA page 4.3-12 would be not conservative.

In addition, it is unclear to the staff what basis would lead to the numerical value 0.026, as shown in LRA page 4.3-12, for the transformed oxygen for stainless steels. Also, the CUF for the decay heat injection Class 1 piping stainless steel Tee under air environment is not included in LRA Table 4.3-2 but the environmentally adjusted CUF for this location is shown in Table 4.3-3. It is unclear to the staff how the CUF for this location was calculated.

Request:

1. Provide the basis that 40-year CUF instead of 60-year CUF can be used as the basis for calculating the environmentally adjusted CUF.

2. Confirm that the transformed oxygen for the stainless steel is 0.026 when the dissolved oxygen (DO) level is below the threshold value of 0.05 ppm, or provide a corrected value.

3. Provide the following input data used for the fatigue analysis for Decay Heat Injection Piping: Temperature; Transient set; Baseline CUF value being multiplied by the F_{en} factor.

Response

1. *The response to RAI 4.3.1-2 provides a discussion supporting the conclusion that the design transient set will not be exceeded. In addition, the LRA will be revised to delete references to the factor of 1.5.*

2. *The transformed oxygen used in the environmentally assisted fatigue (EAF) evaluation of the surge line was 0.26 with dissolved oxygen less than 0.05 ppm. A value of 0.26 is consistent with NUREG/CR-5704 Equation 8(c) for dissolved oxygen less than 0.05 ppm. The LRA, which reported a value of 0.026, will be corrected to 0.26. Refer to the LRA changes in Enclosure 2.*

3. *For the decay heat injection piping tee the maximum fluid temperature observed during cooldown is 210°F. The fluid in the DHI tee is initially at 90°F until the DHRS is actuated during cooldown when the RCS temperature is below 280°F. The DHI Tee is downstream of the Decay Heat Removal System (DHRS) coolers and temperature*

increases from 90°F to 210°F almost instantaneously after DHRS actuation and then decreases exponentially to 120°F in approximately 4 hours. The transient set included in the fatigue evaluation includes 240 cooldown cycles plus 30 OBE events resulting in 650 total OBE cycles, 30 OBE cycles are combined with heatup and cooldown and 620 OBE cycles separately. The baseline unadjusted CUF is 0.00433.

RAI 4.3.3-2

Background:

LRA Table 4.3-3 shows the results of the environmentally assisted fatigue usage evaluations.

Issue:

Clarifications are necessary to enable the staff to complete its review. For example, on the 5th row, "Surge line piping up to but not including weld piping next to weld overlays (SS)" the F_{en} value is shown as a range of values instead of a single value for the location. In addition, several other issues concerning the environmental fatigue evaluation require clarification, as identified in the staff Request 2 through 7. In particular, it is unclear to the staff what the intention and basis are for the second sentence of the third paragraph on LRA Page 4.3-12, which reads, "The environmental correction factor F_{en} from NUREG/CR-5704 was used to determine the number of allowable cycles for each load pair".

Request:

1. Specify the F_{en} value used for the component described on the 5th row of the table.

2. Provide the source document that specified the extraneous 30,000 power loading and unloading transients in the CR-3 design basis as indicated in Note 1 under the LRA Table 4.3-3.

3. Specify the design cycles of the loading-unloading transients. Explain why there are 48,000 cycles and 2,600 cycles shows up in Note 2 under the LRA Table 4.3-3. Provide the basis for cycle reductions for this particular transient from 48,000 to 2,600.

4. Describe the revisions made to Transient 22, as indicated in Note 2 under LRA Table 4.3-3. Also, describe the impact of fatigue results due to such modifications.

5. Describe the role that the cited reference NUREG/CR-6717 plays in the CR-3 environmental fatigue analysis when, as stated in LRA Section 4.3.3, you used NUREG/CR-6583, NUREG/CR-5704, and an open literature for calculating F_{en} for components made of carbon/low-alloy steels, stainless steels, and nickel alloys, respectively. Also, please identify the open literature mentioned here.

6. Summarize the integration method, and provide references, stated in the third paragraph on LRA Page 4.3-12, which you used for F_{en} determination.

7. Clarify the last part in the Issue segment above. What are the allowable cycles? Explain why F_{en} can be used as basis to determine the number of the so-called allowable cycles.

Response

1. *As described in the LRA, the CUF of 1.54 reported in the LRA is based on fatigue penalty factor (F_{en}) values that varied between 2.55 and 15.35 and a specific F_{en} value cannot be assigned to this CUF since it was obtained by integration of transformed metal service temperature as described below.*

   For the stainless steel surge line piping, the equations for the fatigue penalty factors F_{en} were taken from NUREG/CR-5704. The F_{en} values are a function of dissolved oxygen (DO) level, metal service temperature and strain rate, as described in MRP-47, Revision 1, Section 4.2. The effects of metal service temperature were considered but transformed strain rates were assumed to be at saturation and dissolved oxygen was considered as being less than 0.05 ppm.

   Transformed Strain Rate

   Transformed strain rates were assumed to be at the saturation value of ln(0.001). This corresponds to a strain rate of 0.0004%/sec or less.

   Transformed Metal Service Temperature

   For each PV (whether it is a Peak or a Valley), the metal temperature is known from the Surge Line Functional Specification. For each load set pair, the F_{en} values were calculated based on the varying metal temperature values from the valley to the peak will be integrated. The multiplication of the resulting F_{en} factor - after integration - by the usage factor in air for that particular load set pair (from the Valley to the Peak) results in the usage factor with consideration of the environmental effects for that particular load set pair. This means that for each load set pair: $U_{en} = F_{en} * U_{in\text{-}air}$.

   For each integration point from the Valley to the Peak, the transformed temperature T is calculated as specified for stainless steel in Subsection 4.2.4 of MRP-47, Rev. 1: $T^* = 0.0$ for $T < 392°F$, and $T^* = 1.0$ for $T \geq 392°F$.*

   Transformed Dissolved Oxygen

   For the stainless steel surge line, it was assumed that dissolved oxygen is less than 0.05 ppm. $O^* = 0.260$.

   Fatigue Calculation

   Using the methodology described above, the ASME Section III structural/stress analyses performed in the 1990 – 1992 timeframe (BAW-2127) for the stainless steel surge line piping was re-evaluated to extract the variations of metal service temperature to calculate environmental correction factors F_{en}. The CUF is permitted to exceed 1.0 when considering the Functional Specification 40-year design transients. With regard to *the methodology discussed above, the following are relevant relative to calculation of environmentally-adjusted CUFs for the surge line.*

- *In the main fatigue usage calculations (based on the heatups, cooldowns and Transient 22-HPI Valve Test), the F_{en} values are calculated as a function of the temperature changes between the Valley and the Peak (Integration of the F_{en} values ranged between 2.55 when metal temperature is less than 392°F to a maximum of 15.35 when metal temperature equals or exceeds 392°F). In addition, all the F_{en} calculations are based on the most severe strain rate of 0.0004 % / sec, which is the "saturation strain rate."*
- *In the fatigue usage calculations for the low stratification transients, the most severe F_{en} of 15.35 is used.*
- *For all the full-flush cycles, the most severe F_{en} of 15.35 is used.*
- *For thermal striping by itself (thermal striping fluctuations), the most severe strain amplitude is less than 0.097%, and F_{en} is equal to 1.0 for thermal striping.*

2. *The source documents include the original reactor vessel stress report and the current CR-3 RCS Functional Specification. The RV stress report evaluation of the outlet nozzle included 48,000 loading and unloading cycles, but the CR-3 RV Design Specification and RCS Functional Specification specified only 18,000 loading and unloading cycles.*

3. *The CR-3 Reactor Coolant System (RCS) Functional Specification states that the 40-year design basis cycles for power loading and unloading is 18,000. A review of CR-3 operating history indicated that the actual number of power loading and unloading transients expected over a 60-year plant life is less than 2,600 cycles since plant operation has historically and will continue to be base loaded. Therefore, 2,600 cycles were used in the EAF evaluation of the surge line.*

4. *Transient 22, High Pressure Injection Valve test, includes the periodic testing of the HPI safety injection, HPI suction check valves, and Core Flood Tank Check Valve tests. The Core Flood Tank check valve test conditions are included in the normal plant cooldown transients. The HPI safety injection test and HPI suction check valve test are described for four different operating conditions (see BAW-2127, Section 4.5.3.3). The original number of design cycles for 40-year original plant design life for the HPI safety injection test is 40 and HPI suction check valve test is 156. However, CR-3 changed the HPI test procedure and no longer performs these tests as was assumed in BAW-2127.*

   As of December 2007, CR-3 has logged a maximum of 13 HPI test cycles per HPI valve. The HPI flow test is now performed during refueling outages and the latest procedure requires that the reactor vessel head be removed as a prerequisite for performing the HPI test. Therefore, there should be no surge line transients associated with future HPI test events. Hence, the total cycle number for the purpose of the surge line evaluation is 13 versus the design value of 40 since all future testing will be performed without any perturbation of the surge line at temperature. With regard to the HPI check valve test, the HPI flow test consists of both HPI pump test and check valve test. The HPI check valve test is combined with makeup pump MUP-1B test in the procedure. The HPI check valve test is not differentiated from the HPI system test. Therefore the second set of test Transient 22 for HPI check valve testing does not nor did it ever apply to CR-3.

The design cycles for the HPI suction valve tests were reduced from 156 to 0 for the EAF evaluation of the surge line.

5. *The cited reference NUREG/CR-6717 was included for background information only, since it includes discussions of environmental penalty factors for carbon steels, low alloy steels and austenitic stainless steels and was published after NUREG/CR-5704 and NUREG/CR-6583. For the CR-3 LRA, the F_{en} correction factors for carbon and low alloy steel were obtained from NUREG/CR-6583, and F_{en} correction factors for austenitic stainless steel were obtained from NUREG/CR-5704. NUREG/CR-6717 F_{en} correction factors and transformed parameters were not used for CR-3. The open literature reference is provided on page 4.3-12 of the LRA.*

6. *See response to Item 1 above.*

7. *The environmental penalty factor is used to determine the number of allowable cycles for a given alternating stress range for each load pair. The number of design cycles is divided by the allowable cycles considering environmental effects for each load pair to calculate incremental fatigue usage. See response to Item 1 above for a description of the methodology used.*

RAI 4.3.3-3

Background:

LRA Section 4.3.3 describes the environmental fatigue evaluation and the results are presented in LRA Table 4.3-3, including the F_{en} values determined for each component or location evaluated.

Issue:

LRA Table 4.3-3 shows a F_{en} value of 2.45 being used for all of the locations that use low alloy steels. It is known that F_{en} depends on material, strain rates, temperature and the dissolved oxygen (DO) concentration of the reactor water. For low alloy steel and carbon steels to maintain at this particular F_{en} value, 2.45, it requires that the DO is maintained at or below the threshold level of 0.05 ppm.

Request:

1. Summarize CR-3's experience in control of DO level in the reactor water since the plant startup. Describe all water chemistry programs CR-3 has used, including procedures and requirements used for managing DO concentration as well as the inception date of each water chemistry program.

2. Provide a historic summary of the DO level since plant startup. Estimate the fraction of time of the CR-3 operating history thus far that the DO level exceeded 0.05 ppm.

3. Describe how reactor water samples were taken, including the sampling locations. If samples were taken from a single location, justify that the DO data sampled are applicable to all NUREG/CR-6260 locations in CR-3 for the F_{en} calculations.

Response

The CR-3 Optimized Primary Chemistry Program meets the requirements detailed in the EPRI Water Chemistry Guidelines. The Program provides programmatic guidance to control primary water chemistry and defines the parameters (i.e., RCS dissolved oxygen) to be monitored and the sampling frequencies during all modes of operation.

CR-3 controls oxygen in the RCS by maintaining a hydrogen overpressure in the Make-Up Tank, thereby maintaining an excess hydrogen inventory in the RCS. This ensures that oxygen introduced in the system and oxygen species produced by radiolysis are adequately suppressed. FSAR Table 4-10 specifies that RCS dissolved oxygen must be maintained below 100 ppb under steady-state operation and 1000 ppb under transient conditions. The Program also states that dissolved oxygen must be reduced to < 100 ppb prior to exceeding 250°F during heatup. However, the normal value for dissolved oxygen is ≤ 5 ppb, and is controlled at levels significantly lower than 5 ppb.

CR-3 utilizes Action Levels, consistent with the EPRI guidelines, which define remedial actions to be taken when control parameters (i.e., RCS dissolved oxygen) are confirmed to be outside their specified limits. The dissolved oxygen limits for the Action Levels are within the EPRI guidelines. The response for Action Level 1 (RCS dissolved oxygen > 5 ppb) includes returning the oxygen concentration to normal within 7 days. The response for Action Level 2 (RCS dissolved oxygen > 100 ppb) includes returning the oxygen concentration to within the appropriate Action Level 2 value within 24 hours. The response for Action Level 3 (RCS dissolved oxygen > 1000 ppb) includes an orderly shutdown initiated immediately with reduction of RCS coolant temperature to < 250°F as rapidly as plant constraints permit.

RCS dissolved oxygen records between December 31, 1992 and December 5, 2007 were obtained from the CR-3 Environmental and Chemistry Section's computerized Chemistry Data Management System.

Prior to December 31, 1992, CR-3 did not maintain RCS dissolved oxygen records. During that time the expectation that maintaining overpressure of hydrogen in the Make-Up Tank and maintaining RCS hydrogen > 15 cm^3/kg would ensure that RCS dissolved oxygen levels would remain < 5 ppb. Therefore, there is no reason to believe that RCS dissolved oxygen levels prior to December 31, 1992 were significantly different from those documented after this date.

An examination of the records shows that the level of dissolved oxygen in the RCS has been maintained below 5 ppb, when T_{RCS} > 250°F, with few exceptions.

The following tables list those occurrences between December 31, 1992 and December 5, 2007 in which dissolved oxygen levels exceeded 5 ppb during Modes 1 through 4:

Number	*Date*	*Mode*	*Maximum RCS Dissolved Oxygen (ppb)*
1	*06/18/1994*	*3*	*10*
2	*06/20/1994*	*1*	*10*
3	*05/12/1995*	*1*	*< 10*

Number	*Date*	*Mode*	*Maximum RCS Dissolved Oxygen (ppb)*
4	*05/20/1995*	*1*	*< 10*
5	*05/21/1995*	*1*	*< 10*
6	*06/05/1995*	*1*	*< 10*
7	*05/04/1996*	*4*	*15*
8	*11/08/1999*	*4*	*4540*
9	*11/10/1999*	*3*	*< 10*
10	*12/08/1999*	*1*	*< 10*
11	*03/15/2000*	*1*	*6*
12	*09/14/2000*	*4*	*200*
13	*05/21/2001*	*3*	*8*
14	*05/31/2001*	*1*	*8*
15	*09/29/2001*	*4*	*18*
16	*10/22/2001*	*4*	*1600*
17	*10/23/2001*	*3*	*10*
18	*12/20/2003*	*1*	*< 10*
19	*12/21/2003*	*1*	*< 10*
20	*12/22/2003*	*1*	*< 10*
21	*12/23/2003*	*1*	*< 10*
22	*11/03/2003*	*3, 4*	*3000*
23	*12/14/2004*	*1*	*< 10*
24	*12/06/2005*	*4*	*4970*
25	*12/07/2005*	*4*	*275*
26	*12/08/2005*	*3*	*8*
27	*12/03/2007*	*4*	*30*

Of these occurrences, Nos. 8, 12, 16, 22, 24, and 25 briefly exceeded 100 ppb. According to the data retrieved, the time duration for each occurrence typically ranged between a few minutes to no longer than a day.

Upon reviewing this information with the Environmental and Chemistry Section, the occurrences in which dissolved oxygen exceeded 100 ppb, occurrence Nos. 8, 16, 22, 24, and 25 were associated with the outage exits, and that it was highly unlikely that the dissolved oxygen levels recorded during those occurrences exceeded 5 ppb when the RCS temperature exceeded 250°F. This conclusion was based on the restrictions specified for RCS dissolved oxygen in the procedure for plant heatup. The procedure states that RCS dissolved oxygen must be within specified limits prior to exceeding 250°F.

In the worst-case scenario, if RCS dissolved oxygen levels were indeed greater than 5 ppb for each occurrence noted in the Table above, the total time would be no more than a few days over the lifetime of the plant to-date.

Based on the above, there is reasonable assurance that the Reactor Coolant System dissolved oxygen content has, in effect, remained below 5 ppb when the RCS temperature is greater than 250°F, over the lifetime of the plant to-date.

RAI 4.3.3-4

Background:

The results of weld overlay application for the surge line hot leg nozzle were unacceptable due to presence of indications (flaws) in the weld deposit and the overlay weld was removed. The results of the weld overlay application for the surge line pressurizer nozzle were acceptable.

Issue:

The unacceptable weld overlay for the surge line hot leg nozzle raises concerns on the validity of the environmentally adjusted CUF values for the 5th and 6th items shown in LRA Table 4.3-3 "Surge line piping up to but not including weld piping next to weld overlays (SS);" and "Surge line hot leg nozzle and stainless steel piping adjacent to weld overlay (SS)," respectively, since the CUFs of these two locations will be affected by the: (1) application of the weld overlay; (2) removal of the weld overlay; and, (3) reapplication of weld overlay, if this occurs. These above activities cause the stress at the weld overlay and surrounding areas to deviate from the stress state defined in the CLB.

During the audit, the applicant indicated that reapplying the weld overlay for the surge line hot leg nozzle is scheduled for the upcoming refueling outage. The staff noted that a written license renewal commitment for reapplying this weld overlay was not included in the LRA. Furthermore, the CUF validity concern extends to the weld overlay on the surge line pressurizer nozzle since the stress state for the 7th item of LRA Table 4.3-3 will deviate from the stress state defined in the CLB because of the existence of the weld overlay.

Request:

1. Describe how the CUFs shown in LRA Table 4.3-3 for the 5th, 6th, and 7th items (as described above) were determined.

2. Reassess the CUF for LRA Table 4.3-3, Items 5 and 6 when the weld overlay is reapplied.

3. Describe the transient set and cycles used for CUF calculations for the three components (locations) of concern. Confirm that the cycles used are the 60-year projected values.

4. Clarify whether or not a full structural weld overlay for the surge line hot leg nozzle will be reapplied.

5. Discuss the purpose of the full structural weld overlay for the pressurizer surge nozzle and the surge line hot leg nozzle.

6. Provide a discussion of any other structural changes made that could affect fatigue results but are not already discussed in the LRA.

Response

1. *The environmentally-adjusted U_{en} values for pressurizer surge line piping up to, but not including, piping adjacent to the weld overlays is discussed in response to RAI 4.3.3-2. The pressurizer surge nozzle and hot leg surge nozzle weld overlays were applied in the Fall 2007. The weld overlay, which was applied to the hot leg surge nozzle in the Fall of 2007, was partially removed after discovery of a defect in the weld. The repair was evaluated by AREVA NP and the conclusions of the ASME Section III full weld overlay structural analysis were found to remain applicable to the as-left condition of the hot leg surge nozzle. The EAF assessment reported in the CR-3 LRA for these nozzles considers the weld overlay repair, the modified hot leg surge nozzle after removal of the weld overlay, and the original analysis of record for the portion of the pressurizer and hot leg surge nozzles not affected by the weld overlay. The environmentally-adjusted U_{en} values at these locations were obtained by multiplying bounding Fen values by the 40-year CUF values as discussed below.*

   *In accordance with ASME III analysis of hot leg surge nozzle weld overlay (CR-3 LRA, Table 4.3-2), the CUF for the stainless steel safe end adjacent to the weld overlay is 0.118, which includes a contribution of 0.1067 due to striping and 0.0117 due to NSSS design transients. As discussed in the response to RAI 4.3.3-2, the most severe strain amplitude due to thermal striping is less than 0.097% and F_{en} is equal to 1.0 for thermal striping. Therefore, the U_{en} for the stainless steel safe end connected to the hot leg surge nozzle is 0.1067+ (0.0117*15.35) = 0.29.*

   *In accordance with ASME III analysis of the pressurizer surge nozzle weld overlay, the CUF at the inside surface of the stainless steel pipe adjacent to the weld overlay is 0.062; the maximum CUF of 0.8136 (reported in the CR-3 LRA, Table 4.3-2, Item 40) is at the outside surface of the stainless steel safe end and is not subject to environmental adjustment. Therefore, the U_{en} for the stainless steel safe end connected to the pressurizer surge nozzle is 0.062*15.35 = 0.95.*

2. *Table 4.3-3 of the LRA, Items 5, 6, and 7, include the weld overlays as described in Item 1 above.*

3. *The transient set used for the structural evaluation of the surge line piping, surge line hot leg nozzle (including weld overlay), and pressurizer surge nozzle (including weld overlay) are consistent with the governing NSSS Design Transients identified in the CR-3 FSAR, Table 4-8, with specific modifications for the surge line, hot leg surge nozzle, and pressurizer surge nozzle as described in BAW-2127, Section 4.*

4. *The intent is to re-apply a full structural weld overlay for the surge line hot leg nozzle during the next refueling outage. As described in Item 1 above, the environmentally-adjusted U_{en} value for the hot leg surge nozzle safe end covers both the full weld overlay and the as-left condition of the hot leg surge nozzle with partial removal of the overlay.*

5. *The purpose of the full structural weld overlay for the pressurizer surge nozzle and the surge line hot leg nozzle is for mitigation of PWSCC of the nickel based alloy 82/182 welds that connect the carbon steel nozzles to the stainless steel safe ends.*

6. *All structural changes made to the CR-3 plant from beginning of plant operation through December 2008 are included in the CR-3 LRA. Changes to the CLB that occur during the NRC review of the LRA are evaluated in accordance with 10 CFR Part 54.21 (b).*

RAI 3.3.2.2.1-1

Background:

LRA Sections 3.3.2.2.1 (for Auxiliary Systems) and 3.4.2.2.1 (for Steam and Power Conversion Systems), both state that the TLAAs on fatigue are addressed separately in Section 4.3. In addition, both of these LRA sections involve line items cited with Note J (identified in LRA Tables 3.3.2 Series and LRA Table 3.4.2 Series), which indicates that neither the component nor the material and environment combination for the components in these systems are evaluated in NUREG-1801.

Issue:

It is unclear to the staff whether LRA Section 4.3 has covered fatigue TLAA for the components under groups of Auxiliary Systems (AUX), and Steam and Power Conversion (SPC), as the applicant claimed. Specifically, LRA Table 3.3.2 series and Table 3.4.2 series identified that the following components are managed by means of TLAA evaluation:

> EFP-3 Diesel Engine Exhaust Expansion Joints and Silencers, standpipes, hydrants, and tanks; Deaerator, Expansion Joints, Feedwater Booster Pumps, tanks, Feedwater Heaters, Main Feedwater Pumps.

The staff was not able to locate any of these items in LRA Section 4.3 as the applicant stated. Note that the above list does not include piping, which is covered under LRA Section 4.3.2.2 for B31.1.0 Non-Class 1 piping.

Request:

1. Identify under which subsections of LRA Section 4.3 these components are covered.

2. Discuss the methods used for the TLAA analysis for these components.

<u>Response</u>

1. *Non-Class 1 Piping components, regardless of whether or not they were aligned to a NUREG-1801, Revision 1, Volume 2 Item, were evaluated under Subsection 4.3.2.2. In this context, the term "piping components" includes those items referenced in NUREG-1801, Revision 1, Section IX.B, on page IX-4:*

   > *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.*

2. *The components were sorted into two categories, those whose cycles track with plant heatups and cooldowns (such as main steam and feedwater systems) and those that do not (such as the emergency diesel generator system).*

   For those systems in the first category, a generic evaluation was performed to validate that 7,000 cycles would not be exceeded to demonstrate that the analyses remain valid for the period of extended operation. The analysis is described in the CR-3 LRA on pages 4.3-10 and 4.3-11.

   For those systems in the second category, a specific evaluation of the components' operating history was performed, a basis provided for future operation, and a disposition provided. The systems and associated components in this category are as follows:

   a. *Air Handling Ventilation and Cooling System (See LRA Subsection 2.3.3.1.) and Emergency Feedwater Pump Building Ventilation System (See LRA Subsection 2.3.3.18.): EFP-3 Diesel Engine Exhaust Expansion Joints, Silencers, and piping – The functional design specification was reviewed to determine the design number of cycles associated with the introduction of emergency feedwater. In addition to these occasions, the diesel is tested according to the requirements of the Inservice Testing Program. The program plan indicates that the pump is tested quarterly. Although not original plant equipment, it has been treated as such. This resulting number of cycles is less than 7,000. Therefore, the analysis was projected to the end of the period of extended operation (10 CFR 54.21(c)(1)(ii)).*

   b. *Liquid Sampling System (See LRA Subsection 2.3.3.20.) and Post Accident Liquid Sampling System (See LRA Subsection 2.3.3.21.): piping and components – Since there was the potential to induce a full temperature cycle each time a sample is drawn, an evaluation of the cyclic behavior of the sampling systems was required. A generic stress analysis was performed for these piping components based on the seismic support criteria for 2 in. and under piping and the number of anticipated cycles for 60 years. The appropriate stress range reduction factor was applied to the allowable stress, and it was demonstrated that these piping components will remain qualified. Therefore, the analysis was projected to the end of the period of extended operation (10 CFR 54.21(c)(1)(ii)).*

   c. *Emergency Feedwater System (See LRA Subsection 2.3.4.8.): turbine drive and associated piping for the turbine-driven emergency feedwater pump – This evaluation is an extension of a. above. In addition to the cycles previously described, the turbine-driven pump requires a full flow test on the turbine-driven Emergency Feedwater Pump (EFP-2) each refueling outage as set forth by the NRC in Generic Letter 89-04, Position 9, concerning pumps that are normally tested in minimum-flow recirculation lines, and a commitment to perform such a test. This test is performed in addition, and as a supplement, to ASME Code, Section XI, quarterly testing of EFP-2 in the minimum-flow recirculation line. These additional cycles were added to those calculated in a. above and resulted in less than 7,000 total cycles. Therefore, the analysis was projected to the end of the period of extended operation (10 CFR 54.21(c)(1)(ii)).*

d. *Emergency Diesel Generator System (See LRA Subsection 2.3.3.33.): Emergency Diesel Generator diesel exhaust piping, expansion joints, and silencers – The Emergency Diesel Generator diesel exhaust piping, expansion joints, and silencers undergo a cycle each time the diesel is started. The number of cycles associated with 60 years of diesel surveillance tests was added to the number of design cycles for a Station Blackout Accident and the number of cycles the diesels were expected to start in response to a degraded voltage condition and resulted in less than 7,000 total cycles. Therefore, the analysis was projected to the end of the period of extended operation (10 CFR 54.21(c)(1)(ii)).*

e. *Fire Protection System (See LRA Subsection 2.3.3.36.): diesel-driven fire protection pumps – The diesel exhaust piping and components for these two pumps are part of the Fire Protection System and were included in the component commodity group "Piping, piping components, standpipes, hydrants, and tanks" in the LRA. The diesel exhaust piping is exposed to diesel exhaust and will undergo a cycle each time the diesel is started. The Fire Pump Surveillance Requirements of the Fire Protection Plan directs that, once every 31 days, the diesel engine starts from ambient conditions. In addition, once every 18 months, it must be verified that the diesel starts from ambient conditions on the auto-start signal. The number of cycles for 60 years was calculated and resulted in less than 7,000 total cycles. Therefore, the analysis was projected to the end of the period of extended operation (10 CFR 54.21(c)(1)(ii)).*

PROGRESS ENERGY FLORIDA, INC.

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50 - 302 / LICENSE NUMBER DPR - 72

ENCLOSURE 2

AMENDMENT #5
CHANGES TO THE LICENSE RENEWAL APPLICATION

Amendment #5 Changes to the License Renewal Application

Source of Change	License Renewal Application Amendment #5 Changes
RAI B.2.6-1	Replace the second sentence of LRA Subsection A.1.1.6, on page A-7, and the third and fourth sentences of LRA Subsection B.2.6 Program Description, on page B-26, with the following: The augmented inspections for the CASS reactor vessel internals components are in conformance with MRP-227, "Pressurized Water Reactor Internals Inspection and Evaluation Guidelines." When a Safety Evaluation Report is issued for MRP-227, any required actions that affect the aging management strategy for these components will be incorporated into the program documents.
RAI B.2.8-2, RAI B.2.8-3	Replace items 4), 5), and 6) of the second paragraph in LRA Subsection A.1.1.8, on page A-8, with the following: (4) guidance for torquing and closure requirements based on the recommendations of EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," (with exceptions noted in NUREG-1339), EPRI TR-104213, "Bolted Joint Maintenance & Applications Guide," and EPRI 5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Personnel," Volumes I and II, (5) a centralized procedure based on EPRI NP-5769, EPRI TR-104213, and EPRI-5067 containing guidance regarding bolted joint leak tightness and pre-installation inspections consistent with the recommendations of those documents, (6) periodic examinations of a representative sample of bolting identified as potentially having yield strength ≥150 ksi for SCC consisting of periodic in situ ultrasonic testing or, alternatively, surface examination or bolt replacement, with sample sizes based on EPRI TR-107514 methodology, Revise the following enhancement items for the Bolting Integrity Program in LRA Subsection B.2.8, on page B-31 to read as follows: Program Elements Affected • **Preventive Actions** 3) The Bolting Integrity Program procedures will include guidance for torquing and closure requirements based on the guidance of EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," (with exceptions noted in NUREG-1339), EPRI TR-104213, "Bolted Joint Maintenance & Applications Guide," and EPRI 5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Personnel," Volumes I and II. • **Parameters Monitored/Inspected** The Bolting Integrity Program will include periodic ultrasonic testing (UT) examination of a representative sample of bolting identified as potentially having yield strength ≥150 ksi for cracking. (continued)

Source of Change	License Renewal Application Amendment #5 Changes
RAI B.2.8-2, RAI B.2.8-3 (continued	• **Detection of Aging Effects** 2) The Bolting Integrity Program will include periodic examination of a representative sample of bolting identified as potentially having yield strength ≥150 ksi. The Bolting Integrity Program includes periodic in situ UT examinations of these bolts for SCC or, alternatively, bolting may be removed for surface examinations or replaced. Sampling sizes will be based on methodology in EPRI TR-107514, "Age-Related Degradation Inspection Method and 'Demonstration: In Behalf of Calvert Cliffs Nuclear Power Plant License Renewal Application." • **Corrective Actions** 1) The Bolting Integrity Program procedures will include guidance for torquing and closure requirements based on the recommendations of EPRI NP-5769, (with exceptions noted in NUREG-1339), EPRI TR-104213, and EPRI 5067.
RAI B.2.10-1, RAI B.2.10-2, RAI B.2.10-3	Replace the second paragraph of LRA Subsection A.1.1.10, on page A-9, with the following: The Program will be enhanced to: (1) include the Nuclear Services and Decay Heat Seawater System Pumps in a periodic inspection and/or rebuild program. This Program will be initiated during the current license period and inspect one or more pumps prior to the period of extended operation, (2) subject the Nuclear Services and Decay Heat Seawater System Discharge Conduits to inspection and evaluation subsequent to the SG replacement project, but prior to the period of extended operation, in order to determine the extent of activities required during the period of extended operation to support the intended function of these components, (3) incorporate hardness/scratch testing for selective leaching into the examinations of susceptible pumps and valves and, if evidence of degradation is detected, of seawater heat exchanger tubesheet cladding, (4) incorporate Nuclear Services and Decay Heat Seawater System Intake Conduit inspections for degraded or missing concrete lining. Affected areas will be monitored to assure no loss of intended function until such time as the lining can be repaired, (5) incorporate acceptance criteria into procedures for inspections for biofouling and maintenance of protective linings, and (6) establish periodic maintenance activities for Nuclear Services and Decay Heat Seawater System expansion joints prior to the period of extended operation. Add the following enhancements to LRA Subsection B.2.10, on page B-38: <u>Program Elements Affected</u> • **Detection of Aging Effects** 1) Examination of susceptible pumps and valves for selective leaching will incorporate hardness/scratch testing. Visual examination of seawater heat exchanger tubesheet cladding will be supplemented with hardness/scratch testing if evidence of degradation is detected. 2) Nuclear Services and Decay Heat Seawater System Intake Conduits are inspected for degraded/missing concrete lining. Affected areas will be monitored to assure no loss of intended function until such time as the lining can be repaired. • **Acceptance Criteria** Program procedures will be enhanced to include acceptance criteria for inspections for biofouling and maintenance of protective linings.

Source of Change	License Renewal Application Amendment #5 Changes
RAI B.2.11-1, RAI B.2.11-2	Add the following paragraph to LRA Subsection A. 1.1.11 on page A-9: Prior to the period of extended operation, (1) enhance procedures and activities credited for performance of physical inspections to reflect that inspections of components exposed to closed-cycle cooling water will be performed as made available on an opportunistic basis, (2) flag procedures and activities credited with performance monitoring of parameters in the Instrument Air and Secondary Services Closed Cycle Cooling Water Systems to assure pump and heat exchanger performance are identified as license renewal activities, and (3) flag procedures associated with closed cycle cooling water chemistry controls to identify chemistry controls associated for in-scope systems as License Renewal activities. Revise LRA Subsection B.2.11 on page B-40 as follows: Change the NUREG-1801 Consistency to read: The CCCW System Program is an existing program that, following enhancement, will be consistent with NUREG-1801, Section XI.M21, with exceptions. Replace the parameters monitored/inspected exceptions with the following exception: <u>Program Elements Affected</u> • **Parameters Monitored/Inspected** Performance of Closed-Cycle Cooling Water System pump and heat exchanger parameters in the Instrument Air System is verified by monitoring of compressor and dryer performance including monitoring of Instrument Air header pressure and dew point. The Instrument Air System closed cycle cooling loop provides cooling water to the compressors, as well as the intercooler and aftercooler for heat and moisture removal in support of operation of the Instrument Air dryer. Therefore, adequate flow and heat transfer of the Instrument Air System closed cycle cooling loop is verified by performance monitoring of the instrument air compressors and dryers. Incorporate the following enhancements: <u>Program Elements Affected</u> • **Preventive Actions** Procedures associated with Closed-Cycle Cooling Water System chemistry controls will be flagged to identify chemistry controls associated with in scope systems as License Renewal activities. • **Parameter Monitored/Inspected** 1) Procedures and activities credited with the performance of physical inspections will be enhanced to reflect that inspections of components exposed to closed-cycle cooling water will be performed as made available. 2) Procedures and activities credited with performance monitoring of Instrument Air and Secondary Services Closed Cycle Cooling Water System parameters to assure pump and heat exchanger performance will be flagged as License Renewal activities.

Source of Change	License Renewal Application Amendment #5 Changes
RAI B.2.14-1	Replace the final, parenthetical sentence at the end of the second paragraph of LRA Subsection A.1.1.14, on page A-11, with the following: (Subsequent testing will be performed at an interval of 10 years after the initial field service testing.) Revise enhancement 3) under Detection of Aging Effects in LRA Subsection B.2.14, on page B-49 to read as follows: <u>Program Elements Affected</u> • **Detection of Aging Effects** 3) Enhance the Program, consistent with the intent of NFPA 25, to either replace the sprinkler heads prior to reaching their 50-year service life or perform field service testing of representative samples from one or more sample areas by a recognized testing laboratory. Subsequent testing will be performed at an interval of 10 years after the initial field service testing.
RAI B.2.21-1	Revise the eighth sentence of the Program Description in LRA Subsection B.2.21 on page B-69, to read: The volumetric inspections will be completed prior to the end of, and within the last ten years of, the current operating period.
RAI B.2.22-1	Replace the second paragraph of Subsection A.1.1.22, on page A-14, witht the following: Prior to the period of extended operation, the Program will be enhanced to: (1) incorporate measures to assure the integrity of surfaces that are inaccessible or not readily visible during both plant operations and refueling outages, and (2) incorporate inspection attributes for degradation of coatings. Revise LRA Subsection B.2.22 on page B-72 as follows: Change the NUREG-1801 Consistency to read: The External Surfaces Monitoring Program is an existing program that, following enhancement, will be consistent with NUREG-1801, Section XI.M36, with exceptions. Incorprate the following exceptions: <u>Program Elements Affected</u> • **Scope of Program** The Program is credited for managing materials beyond carbon steel and aging effects for materials beyond carbon steel. The program utilizes appropriate inspection attributes for visual examinations of the specified materials for the aging effects it manages. (continued)

<table>
<tr><th>Source of Change</th><th>License Renewal Application Amendment #5 Changes</th></tr>
<tr><td>RAI B.2.22-1
(continued)</td><td>

- **Parameters Monitored/Inspected**
The Program is credited for utilizing inspection parameters beyond those specified in NURG-1801. The program utilizes inspection attributes that can be implemented during visual examinations of the specified materials for the aging effects it manages, including inspection of finned tube heat transfer surfaces for evidence of fouling.

- **Detection of Aging Effects**
The Program is credited for detection of aging effects in addition to those specified in NUREG-1801. Examination procedures will include inspection attributes relevant to corrosion of metals, such as visual detection of loss of material, and evidence of corrosion mechanisms, such as rust/oxidation, sensitization, and discoloration.

In addition, delete Program enhancements 1) and 2) under **Scope of Program** and delete the enhancement under **Parameters Monitored/Inspected**.
</td></tr>
<tr><td>RAI B.2.26-1</td><td>

Add the following sentence to the penultimate paragraph in the Operating Experience discussion of LRA Subsection B.2.26 on page B-82.

However, subsequent to the IN 99-10 review, the methodology at CR-3 has been enhanced to use individual tendon lift-off force linear regression analysis as discussed in IN 99-10.
</td></tr>
<tr><td>RAI 4.3.1-2</td><td>

Revisions to the fatigue analyses have resulted in changes to the methods used to comply with 10 CFR 54.21(c)(1) as shown on LRA Table 4.1-1. Therefore, the table has been changed as shown below:

<table>
<tr><td>Fatigue Analyses (NSSS Components)</td><td>----------</td><td>4.3.1</td></tr>
<tr><td>Reactor Vessel</td><td>(i)</td><td>4.3.1.1</td></tr>
<tr><td>Reactor Vessel Internals</td><td>(i) and (ii)</td><td>4.3.1.2</td></tr>
<tr><td>Control Rod Drive Mechanism</td><td>(i)</td><td>4.3.1.3</td></tr>
<tr><td>Reactor Coolant Pumps</td><td>(i)</td><td>4.3.1.4</td></tr>
<tr><td>Steam Generators</td><td>(i)</td><td>4.3.1.5</td></tr>
<tr><td>Pressurizer</td><td>(i)</td><td>4.3.1.6</td></tr>
<tr><td>Reactor Coolant Pressure Boundary Piping (USAS B31.7)</td><td>(i)</td><td>4.3.1.7</td></tr>
<tr><td>Implicit Fatigue Analysis (B31.1 Piping)</td><td>----------</td><td>4.3.2</td></tr>
<tr><td>USAS B31.1.0 Piping - RCPB Class 1</td><td>(i)</td><td>4.3.2.1</td></tr>
<tr><td>USAS B31.1.0 Piping - Non-Class 1</td><td>(i) and (ii)</td><td>4.3.2.2</td></tr>
<tr><td>Environmentally-Assisted Fatigue Analysis</td><td>(iii)</td><td>4.3.3</td></tr>
<tr><td>RCS Loop Piping Leak-Before-Break Analysis</td><td>(i)</td><td>4.3.4</td></tr>
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(continued)
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<table>
<tr><th>Source of Change</th><th>License Renewal Application Amendment #5 Changes</th></tr>
<tr><td>RAI 4.3.1-2 (continued)</td><td>
Delete the last three sentences of the third paragraph on page 4.3-2.
Revise the Analysis and Disposition discussions of Subsection 4.3.1.1 to read:
Analysis
For the components that are part of the RV, the maximum CUF is that of the Lower Service Support Structure attachment weld with a CUF of 0.72. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation.
Disposition: 10 CFR 54.21(c)(1)(i) – The analyses remain valid for the period of extended operation
Revise the <u>Cumulative Usage Factors for RV Internals Replacement Bolts</u> discussion of Subsection 4.3.1.2 to read:
<u>Cumulative Usage Factors for RV Internals Replacement Bolts</u>
The RV internals bolts that were replaced at CR-3 include 120 Upper Core Barrel bolts made from A-286, 60 Lower Core Barrel bolts made from X-750, 96 Lower Thermal Shield bolts made from X-750, and 72 Surveillance Specimen Holder Tube (SSHT) bolts made from X-750. The maximum CUF for these components is for the lower thermal shield bolts with CUF of 0.84. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation.
Disposition 10 CFR 54.21(c)(1)(i) – The analyses remain valid for the period of extended operation
Revise the Analysis and Disposition discussions of Subsection 4.3.1.4 to read:
Analysis
The RCP pump cover has the largest 40-year design usage factor at 0.65.
Calculations performed in accordance with N-415.1(a) through N-415.1(f) of the ASME Code, Section III, for the RCP seal and heat exchanger are based on NSSS design transients. The NSSS design transients for CR-3 have not been increased for the period of extended operation.
Disposition: 10 CFR 54.21(c)(1)(i) – The analyses remain valid for the period of extended operation
Revise the Analysis and Disposition discussions of Subsection 4.3.1.5 to read:
Analysis
The maximum CUF for the OTSG is for the EFW Nozzle Studs with a CUF of 0.97. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation.
Disposition: 10 CFR 54.21(c)(1)(i) – The analyses remain valid for the period of extended operation
(continued)
</td></tr>
</table>

Source of Change	License Renewal Application Amendment #5 Changes
RAI 4.3.1-2 (continued)	Revise the Analysis and Disposition discussions of Subsection 4.3.1.6 to read: **Analysis** For the components that are part of the Pressurizer, the Heater Bundle closure seal weld has the highest CUF with a value of 0.86. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation. **Disposition:** 10 CFR 54.21(c)(1)(i) – The analyses remain valid for the period of extended operation Revise the Analysis and Disposition discussions of Subsection 4.3.1.7 to read: **Analysis** For the components that are part of the RCPB piping, the maximum CUF is for the High Pressure Injection/Makeup (HPI/MU) Nozzle safe end with a CUF of 0.95. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation. In accordance with NRC letter (H. Silver) to FPC (P. Beard), "Crystal River Unit 3 - NRC Bulletin 88-08 'Thermal Stress in Piping Connected to Reactor Coolant Systems,' (TAC No. M69621)," dated June 18, 1992, the piping items within the scope of NRC Bulletin 88-08 at CR-3 include the HPI/MU nozzle, safe end, and thermal sleeve. Fatigue of the HPI/MU nozzle, safe end, and thermal sleeve is evaluated above for the period of extended operation. **Disposition:** 10 CFR 54.21(c)(1)(i) – The analyses remain valid for the period of extended operation Delete from Subsection 4.3.2.1 the entire discussion and disposition for Cumulative Usage Factor for HPI/MU Safe End Spool Piece on page 4.3-10. Delete the last three sentences of paragraph four in Subsection A.1.2.2 on page A-29. Replace the third and fourth sentences of Subsection A.1.2.2.1, on page A-29, with: For the components that are part of the RV, the maximum CUF is that of the Lower Service Support Structure attachment weld with a CUF of 0.72. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Replace the third paragraph of Subsection A.1.2.2.2, on page A-30, with: The RV internals bolts that were replaced at CR-3 include 120 Upper Core Barrel bolts made from A-286, 60 Lower Core Barrel bolts made from X-750, 96 Lower Thermal Shield bolts made from X-750, and 72 Surveillance Specimen Holder Tube (SSHT) bolts made from X-750. The maximum CUF for these components is for the lower thermal shield bolts with CUF of 0.84. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). (continued)

Source of Change	License Renewal Application Amendment #5 Changes
RAI 4.3.1-2 (continued)	Replace the fifth sentence of Subsection A.1.2.2.4, on page A-31, with: Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses for the RCP casing, cover, and shaft and the analyses of the RCP seal and heat exchanger performed in accordance with N-415.1(a) through N-415.1(f) of the ASME Code, Section III, are acceptable for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Replace the third and fourth sentences of Subsection A.1.2.2.5, on page A-31, with: The maximum CUF for the OTSG is for the EFW Nozzle Studs with a CUF of 0.97. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Replace the fourth and fifth sentences of Subsection A.1.2.2.6, on page A-32, with: For the components that are part of the Pressurizer, the Heater Bundle closure seal weld has the highest CUF with a value of 0.86. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Replace the third, fourth, and fifth paragraphs of Subsection A.1.2.2.7, on page A-32, with: In accordance with NRC letter (H. Silver) to FPC (P. Beard), "Crystal River Unit 3 - NRC Bulletin 88-08 'Thermal Stress in Piping Connected to Reactor Coolant Systems,' (TAC No. M69621)," dated June 18, 1992, the piping items within the scope of NRC Bulletin 88-08 at CR-3 include the HPI/MU nozzle, safe end, and thermal sleeve. For the components that are part of the RCPB piping, the maximum CUF is for the High Pressure Injection/Makeup (HPI/MU) Nozzle safe end with a CUF of 0.95. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). Replace the third paragraph of Subsection A.1.2.2.8 on page A-33 with: The HPI/MU safe end is welded to a stainless steel spool piece that was analyzed for fatigue analysis in accordance with USAS B31.7 to support NRC Bulletin 88-08. The 40-year CUF for the spool piece is 0.94. Since CR-3 has determined there is no need to increase the number of NSSS design transients for the period of extended operation, the analyses remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i).

Source of Change	License Renewal Application Amendment #5 Changes
RAI 4.3.1.2-1	Revise the FIV Endurance Limit Assumptions discussion of Subsection 4.3.1.2 to read: FIV Endurance Limit Assumptions BAW-10051 calculated stress values for the redesigned RVI and compared them to endurance limit stress values. These endurance limit values were based on an assumed value of 10^{12} cycles for 40 years of operation. Since the fatigue curves at the time of design only went up to 10^{6} cycles, these curves were extrapolated to 10^{12} cycles. The methodology used in BAW-10051 was extended from 40 years to 60 years by multiplying the assumed endurance limit cycles by 1.5 and then using 10^{13} cycles to determine the endurance limit based on more recent ASME fatigue curves which extend now to 10^{11} cycles (Figure 1-9.2.2 of ASME Section III, 1986 Edition). The component item stress values in BAW-10051 were compared to the recalculated endurance limit values and were shown to be acceptable. Therefore, the FIV analysis has been projected to the end of the period of extended operation. Replace the second sentence in the second paragraph of Subsection A.1.2.2.2 with: The methodology used in BAW-10051 was extended from 40 years to 60 years by multiplying the assumed endurance limit cycles by 1.5 and then using 10^{13} cycles to determine the endurance limit based on more recent ASME fatigue curves which extend now to 10^{11} cycles.
RAI 4.3.3-1	Change the value of transformed oxygen in the fifth sentence of the fourth paragraph on LRA Subsection A.1.2.2.10 from 0.026 to 0.26. Change the value of transformed oxygen in the fifth sentence of the fourth paragraph on LRA Subsection 4.3.3 from 0.026 to 0.26.
Progress Energy-Identified Change	Revise the first sentence in the Summary Description of Subsection 4.3.1.3 to correct the ASME Code of reference for the control rod drive mechanism motor tube. The revised sentence should read: The "Type C" control rod drive mechanism (CRDM) motor tube was designed in accordance with ASME Code, Section III, Class A, 1965 Edition with Addenda through Summer 1967, and metal fatigue was considered in the design of the component.

PROGRESS ENERGY FLORIDA, INC.

CRYSTAL RIVER UNIT 3

DOCKET NUMBER 50 - 302 / LICENSE NUMBER DPR - 72

ENCLOSURE 3

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1				
ITEM NO.	**COMMITMENT**	**FINAL SAFETY ANALYSIS REPORT (FSAR) SUPPLEMENT LOCATION**	**PROGRAM IMPLEMENTATION SCHEDULE**	**LICENSE RENEWAL APPLICATION (LRA) SOURCE**
1	In accordance with the guidance of NUREG-1801, Rev. 1, regarding aging management of reactor vessel internals components, CR-3 will: (1) participate in the industry programs for investigating and managing aging effects on reactor internals, (2) evaluate and implement the results of the industry programs as applicable to the reactor internals, and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	A.1.1	As stated in the commitment	Reactor Vessel Internals Aging Management Activities LRA Section A.1.1
2	In accordance with the guidance of NUREG-1801, Rev. 1, regarding aging management of nickel alloy and nickel-clad components susceptible to primary water stress corrosion cracking, CR-3 will comply with applicable NRC Orders and will implement applicable: (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines.	A.1.1	As stated in the commitment	Primary Water Stress Corrosion Cracking of Nickel Alloys LRA Section A.1.1
3	The Program will be enhanced to select an alternate lubricant that is compatible with the fastener material and the contained fluid.	A.1.1.3	Prior to the period of extended operation	Reactor Head Closure Studs Program LRA Section B.2.3
4	The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new program to be implemented. When a Safety Evaluation Report is issued for MRP-227, any required actions that affect the aging management strategy for these components will be incorporated into the program documents.	A.1.1.6	Prior to the period of extended operation	Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program LRA Section B.2.6 RAI B.2.6-1

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1

ITEM NO.	COMMITMENT	FINAL SAFETY ANALYSIS REPORT (FSAR) SUPPLEMENT LOCATION	PROGRAM IMPLEMENTATION SCHEDULE	LICENSE RENEWAL APPLICATION (LRA) SOURCE
5	Program administrative control documents will be enhanced to include: (1) guidance for torquing and closure requirements based on the EPRI documents endorsed by NUREG-1801, (2) requirements to remove instances where molybdenum disulfide lubricant is allowed for use in bolting applications in specific procedures and to add a general prohibition against use of molybdenum disulfide lubricants for bolted connections, (3) guidance for torquing and closure requirements that include proper torquing of the bolts and checking for uniformity of gasket compression after assembly, (4) guidance for torquing and closure requirements based on the recommendations of EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants," (with exceptions noted in NUREG-1339), EPRI TR-104213, "Bolted Joint Maintenance & Applications Guide," and EPRI 5067, "Good Bolting Practices, A Reference Manual for Nuclear Power Plant Personnel," Volumes I and II, (5) a centralized procedure based on EPRI NP-5769, EPRI TR-104213, and EPRI-5067 containing guidance regarding bolted joint leak tightness and pre-installation inspections consistent with the recommendations of those documents, (6) periodic examinations of a representative sample of bolting identified as potentially having yield strength ≥150 ksi for SCC consisting of periodic in situ ultrasonic testing or, alternatively, surface examination or bolt replacement, with sample sizes based on EPRI TR-107514 methodology, (7) examination of NSSS support high strength bolting for SCC concurrent with examinations of the associated supports at least once per 10-year ISI period, and (8) acceptance standards for examination of high strength structural bolting consistent with the recommendations of EPRI NP-5769 or application specific structural analyses.	A.1.1.8	Prior to the period of extended operation	Bolting Integrity Program LRA Section B.2.8, RAI B.2.8-2, RAI B.2.8-3

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1				
ITEM NO.	**COMMITMENT**	**FINAL SAFETY ANALYSIS REPORT (FSAR) SUPPLEMENT LOCATION**	**PROGRAM IMPLEMENTATION SCHEDULE**	**LICENSE RENEWAL APPLICATION (LRA) SOURCE**
6	The Program will be enhanced to: (1) include the Nuclear Services and Decay Heat Seawater System Pumps in a periodic inspection and/or rebuild program. This Program will be initiated during the current license period and inspect one or more pumps prior to the period of extended operation, (2) subject the Nuclear Services and Decay Heat Seawater System Discharge Conduits to inspection and evaluation subsequent to the SG replacement project, but prior to the period of extended operation, in order to determine the extent of activities required during the period of extended operation to support the intended function of these components, (3) incorporate hardness/scratch testing for selective leaching into the examinations of susceptible pumps and valves and, if evidence of degradation is detected, of seawater heat exchanger tubesheet cladding, (4) incorporate Nuclear Services and Decay Heat Seawater System Intake Conduit inspections for degraded or missing concrete lining. Affected areas will be monitored to assure no loss of intended function until such time as the lining can be repaired, (5) incorporate acceptance criteria into procedures for inspections for biofouling and maintenance of protective linings, and (6) establish periodic maintenance activities for Nuclear Services and Decay Heat Seawater System expansion joints prior to the period of extended operation.	A.1.1.10	As stated in the commitment	Open-Cycle Cooling Water System Program LRA Section B.2.10, RAI B.2.10-1, RAI B.2.10-2, RAI B.2.10-3

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1				
ITEM NO.	**COMMITMENT**	**FINAL SAFETY ANALYSIS REPORT (FSAR) SUPPLEMENT LOCATION**	**PROGRAM IMPLEMENTATION SCHEDULE**	**LICENSE RENEWAL APPLICATION (LRA) SOURCE**
7	Administrative controls for the Program will be enhanced to: (1) include in the Program all cranes within the scope of License Renewal, (2) require the responsible engineer to be notified of unsatisfactory crane inspection results involving loss of material, (3) specify the frequency of inspections for the cranes within the scope of License Renewal to be every refueling outage for cranes in the Reactor Building and every two years for cranes outside the Reactor Building, and (4) clarify that crane rails are to be inspected for abnormal wear and that members to be inspected for cracking include welds.	A.1.1.12	Prior to the period of extended operation	Inspection of Overhead Heavy Load and Light Load Handling Systems Program LRA Section B.2.12
8	The Program administrative controls will be enhanced to: (1) include specific guidance for periodic inspection of fire barrier walls, ceilings, and floors including a requirement to notify Fire Protection of any deficiencies having the potential to adversely affect the fire barrier function, (2) include additional inspection criteria as described in NUREG-1801 for penetration seals, (3) include additional inspection criteria for corrosion of fire doors, and (4) specify minimum qualification requirements for personnel performing visual inspections of penetrations seals and fire doors.	A.1.1.13	Prior to the period of extended operation	Fire Protection Program LRA Section B.2.13

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1				
ITEM NO.	**COMMITMENT**	**FINAL SAFETY ANALYSIS REPORT (FSAR) SUPPLEMENT LOCATION**	**PROGRAM IMPLEMENTATION SCHEDULE**	**LICENSE RENEWAL APPLICATION (LRA) SOURCE**
9	The Program will be enhanced to: (1) incorporate a requirement to perform one or a combination of the following two activities: (a) Implement periodic flow testing consistent with the intent of NFPA 25, or (b) Perform wall thickness evaluations to verify piping is not impaired by pipe scale, corrosion products, or other foreign maternal. For sprinkler systems, this may be done by flushing, internal inspection by removing one or more sprinkler heads, or by other obstruction investigation methods, (such as technically proven ultrasonic and X-ray examination) that have been evaluated as being capable of detecting obstructions. (These inspections will be performed before the end of the current operating term. The results from the initial inspections will be used to determine inspection intervals thereafter during the period of extended operation.), (2) perform internal inspections of system piping at representative locations as required to verify that loss of material due to corrosion has not impaired system intended function. Alternately, non-intrusive inspections (e.g., ultrasonic testing) can be used to verify piping integrity. (These inspections will be performed before the end of the current operating term. The results from the initial inspections will be used to determine inspection intervals thereafter during the period of extended operation.), (3) incorporate a requirement to perform a visual inspection of yard fire hydrants annually consistent with the intent of NFPA 25 to ensure timely detection of signs of degradation, such as corrosion, and (4) consistent with the intent of NFPA 25, either replace the sprinkler heads prior to reaching their 50-year service life or revise site procedures to perform field service testing, by a recognized testing laboratory, of representative samples from one or more sample areas. (Subsequent testing will be performed on a representative sample at an interval of 10 years after the initial field service testing.)	A.1.1.14	Prior to the period of extended operation	Fire Water System Program LRA Section B.2.14, RAI B.2.14-1

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1				
ITEM NO.	**COMMITMENT**	**FINAL SAFETY ANALYSIS REPORT (FSAR) SUPPLEMENT LOCATION**	**PROGRAM IMPLEMENTATION SCHEDULE**	**LICENSE RENEWAL APPLICATION (LRA) SOURCE**
10	The Aboveground Steel Tanks Program is a new program to be implemented.	A.1.1.15	Prior to the period of extended operation	Aboveground Steel Tanks Program LRA Section B.2.15
11	The Program will be enhanced to: (1) adjust the inspection frequency for the Diesel-Driven Emergency Feedwater Pump Fuel Oil Storage Tank to ensure an inspection is performed prior to the period of extended operation, (2) inspect the internal surfaces of the Diesel-Driven Fire Pump Fuel Oil Storage Tanks, and (3) develop a work activity to periodically inspect the internal surfaces of the Diesel-Driven Fire Pump Fuel Oil Storage Tanks.	A.1.1.16	Prior to the period of extended operation	Fuel Oil Chemistry Program LRA Section B.2.16
12	The Program will be enhanced to: (1) ensure that neutron exposure conditions of the reactor vessel remain bounded by those used to project the effects of embrittlement to the end of the 60-year extended license period and (2) establish formalized controls for the storage of archived specimens to ensure availability for future use by maintaining the identity, traceability, and recovery of the archived specimens throughout the storage period.	A.1.1.17	Prior to the period of extended operation	Reactor Vessel Surveillance Program LRA Section B.2.17
13	The One-Time Inspection Program is a new program to be implemented.	A.1.1.18	Prior to the period of extended operation	One-Time Inspection Program LRA Section B.2.18
14	The Selective Leaching of Materials Program is a new program to be implemented.	A.1.1.19	Prior to the period of extended operation	Selective Leaching of Materials Program LRA Section B.2.19
15	The Buried Piping and Tanks Inspection Program is a new program to be implemented.	A.1.1.20	Prior to the period of extended operation	Buried Piping and Tanks Inspection Program LRA Section B.2.20

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1				
ITEM NO.	**COMMITMENT**	**FINAL SAFETY ANALYSIS REPORT (FSAR) SUPPLEMENT LOCATION**	**PROGRAM IMPLEMENTATION SCHEDULE**	**LICENSE RENEWAL APPLICATION (LRA) SOURCE**
16	The One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program is a new program to be implemented. CR-3 will perform a volumetric examination of 24 small bore piping butt welds within the last ten years of the original license period.	A.1.1.21	Prior to the period of extended operation	One-Time Inspection of ASME Code Class 1 Small-Bore Piping Program LRA Section B.2.21, RAI B.2.21-1
17	The Program will be enhanced to: (1) incorporate measures to assure the integrity of surfaces that are inaccessible or not readily visible during both plant operations and refueling outages, and (2) incorporate inspection attributes for degradation of coatings.	A.1.1.22	Prior to the period of extended operation	External Surfaces Monitoring Program LRA Section B.2.22, RAI B.2.22-1
18	The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program to be implemented.	A.1.1.23	Prior to the period of extended operation	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program LRA Section B.2.23
19	Program administrative controls will be enhanced to (1) identify the structures that have masonry walls in the scope of License Renewal, and (2) include inspection of the masonry walls in the Machine Shop in a periodic engineering activity (PMID).	A.1.1.29	Prior to the period of extended operation	Masonry Wall Program LRA Section B.2.29 RAI 2.2-06

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1				
ITEM NO.	**COMMITMENT**	**FINAL SAFETY ANALYSIS REPORT (FSAR) SUPPLEMENT LOCATION**	**PROGRAM IMPLEMENTATION SCHEDULE**	**LICENSE RENEWAL APPLICATION (LRA) SOURCE**
20	Program will be enhanced by revising the administrative controls that implement the Program to: (1) identify all License Renewal structures and systems that credit the Program for aging management in the corporate procedure for condition monitoring of structures, (2) require notification of the responsible engineer when below grade concrete including concrete pipe is exposed so an inspection may be performed prior to backfilling, (3) require periodic groundwater chemistry monitoring including consideration for potential seasonal variations, (4) require periodic inspections of the water control structures, i.e., Circulating Water Intake Structure, Circulating Water Discharge Structure, Nuclear Service Sea Water Discharge Structure, Intake Canal, and Raw Water Pits, on a frequency not to exceed five years, (5) require periodic inspections of the Circulating Water Intake Structure submerged portions on a frequency not to exceed five years, (6) identify additional civil/structural commodities and associated inspection attributes and performance standard required for License Renewal in the corporate procedure for condition monitoring of structures, (7) identify additional inspection criteria for structural commodities in the site system walkdown checklist, (8) add inspection of corrosion to the inspection criteria for the bar racks at the Circulating Water Intake Structure as a periodic maintenance activity, (9) add an inspection of the earth for loss of form and loss of material for the Wave Embankment Protection Structure as a periodic maintenance activity, (10) include additional in-scope structures and specific civil/structural commodities in periodic engineering activities, and (11) require periodic inspections of the Fluorogold slide bearing plates used in structural steel platform applications in the Reactor Building.	A.1.1.30	Prior to the period of extended operation	Structures Monitoring Program LRA Section B.2.30

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1				
ITEM NO.	**COMMITMENT**	**FINAL SAFETY ANALYSIS REPORT (FSAR) SUPPLEMENT LOCATION**	**PROGRAM IMPLEMENTATION SCHEDULE**	**LICENSE RENEWAL APPLICATION (LRA) SOURCE**
21	The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program to be implemented.	A.1.1.31	Prior to the period of extended operation	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program LRA Section B.2.31
22	The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program is a new program to be implemented.	A.1.1.32	Prior to the period of extended operation	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program LRA Section B.2.32
23	The Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program to be implemented.	A.1.1.33	Prior to the period of extended operation	Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program LRA Section B.2.33
24	The Metal Enclosed Bus Program is a new program to be implemented.	A.1.1.34	Prior to the period of extended operation	Metal Enclosed Bus Program LRA Section B.2.34
25	The Fuse Holder Program is a new program to be implemented.	A.1.1.35	Prior to the period of extended operation	Fuse Holder Program LRA Section B.2.35

CRYSTAL RIVER UNIT 3 LICENSE RENEWAL COMMITMENTS, REVISION 1				
ITEM NO.	**COMMITMENT**	**FINAL SAFETY ANALYSIS REPORT (FSAR) SUPPLEMENT LOCATION**	**PROGRAM IMPLEMENTATION SCHEDULE**	**LICENSE RENEWAL APPLICATION (LRA) SOURCE**
26	The Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program is a new program to be implemented.	A.1.1.36	Prior to the period of extended operation	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program LRA Section B.2.36
27	Administrative controls for the Program will be enhanced to: (1) include provisions to monitor and trend data for incorporation in test procedures to ensure the projection meets the acceptance criteria and (2) incorporate acceptance criteria tables for accumulated weight losses of monitored Carborundum samples.	A.1.1.37	Prior to the period of extended operation	Carborundum (B_4C) Monitoring Program LRA Section B.2.37
28	The High-Voltage Insulators in the 230KV Switchyard Program is a new program to be implemented.	A.1.1.38	Prior to the period of extended operation	High-Voltage Insulators in the 230KV Switchyard Program LRA Section B.2.38
29	Administrative controls for the Program will be revised to: (1) enhance procedures and activities credited for performance of physical inspections to reflect that inspections of components exposed to closed-cycle cooling water will be performed as made available on an opportunistic basis, (2) flag procedures and activities credited with performance monitoring of parameters in the Instrument Air and Secondary Services Closed Cycle Cooling Water Systems to assure pump and heat exchanger performance are identified as license renewal activities, and (3) flag procedures associated with closed cycle cooling water chemistry controls to identify chemistry controls associated for in-scope systems as License Renewal activities.	A.1.1.11	Prior to the period of extended operation	Closed-Cycle Cooling Water System Program LRA Section B.2.11, RAI B.2.11-1, RAI B.2.11-2